2015

Annual Report on Form 20-F

Statoil

2015

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The Annual Report on Form 20-F is our SEC filing for the fiscal year ended December 31, 2015, as submitted to the US Securities and Exchange Commission.

STATOIL ASA
BOX 8500
NO-4035 STAVANGER
NORWAY
TELEPHONE: +47 51 99 00 00

www.statoil.com

Cover photo: Øyvind Hagen

2015 Annual Report on Form 20-F

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 20-F

(Mark One)

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Date of event requiring this shell company report _________

Commission file number 1-15200

Statoil ASA

(Exact Name of Registrant as Specified in Its Charter)

N/A

(Translation of Registrant's Name Into English)

Norway

(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035, Stavanger, Norway

(Address of Principal Executive Offices)

Hans Jakob Hegge
Chief Financial Officer
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
American Depositary Shares	**New York Stock Exchange**
Ordinary shares, nominal value of NOK 2.50 each	**New York Stock Exchange***

*Listed, not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares of NOK 2.50 each	**3,188,647,103**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

☒ Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

☐ Yes ☒ No

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).**

☐ Yes ☐ No

**This requirement does not apply to the registrant in respect of this filing.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐
Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

☐ Yes ☒ No

1 Introduction

1.1 About the report

Statoil's Annual Report on Form 20-F for the year ended 31 December 2015 ("Annual Report on Form 20-F") is available online at www.statoil.com.

Statoil is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, Statoil files its Annual Report on Form 20-F and other related documents with the Securities and Exchange Commission (the SEC). It is also possible to read and copy documents that have been filed with the SEC at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549, US. You can also call the SEC at 1-800-SEC-0330 for further information about the public reference rooms and their copy charges, or you can log on to www.sec.gov. The report can also be downloaded from the SEC website at www.sec.gov.

Statoil discloses on its website at www.statoil.com/en/about/corporategovernance/statementofcorporategovernance/pages/default.aspx, and in its Annual Report on Form 20-F (Item 16G) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under the New York Stock Exchange (the "NYSE") listing standards.

1.2 Key figures and highlights

Statoil publishes financial data in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).

		For the year ended 31 December			
(in NOK billion, unless stated otherwise)	2015	2014	2013	2012	2011
Financial information					
Total revenues and other income[4)]	**482.8**	622.7	634.5	718.2	670.0
Net operating income	**14.9**	109.5	155.5	206.6	211.8
Net income	**(37.3)**	22.0	39.2	69.5	78.4
Non-current finance debt	**264.0**	205.1	165.5	101.0	111.6
Net interest-bearing debt before adjustments	**122.0**	89.2	58.0	39.3	71.0
Total assets	**966.7**	986.4	885.6	784.4	768.6
Share capital	**8.0**	8.0	8.0	8.0	8.0
Non-controlling interest	**0.3**	0.4	0.5	0.7	6.2
Total equity	**355.1**	381.2	356.0	319.9	285.2
Net debt to capital employed ratio before adjustments	**25.6%**	19.0%	14.0%	10.9%	19.9%
Net debt to capital employed ratio adjusted	**26.8%**	20.0%	15.2%	12.4%	21.1%
Calculated ROACE based on Average Capital Employed before adjustments	**(8.0%)**	2.7%	11.3%	18.7%	22.1%
Operational information					
Equity oil and gas production (mboe/day)	**1,971**	1,927	1,940	2,004	1,850
Proved oil and gas reserves (mmboe)	**5,060**	5,359	5,600	5,422	5,426
Reserve replacement ratio (three-year average)	**0.81**	0.97	1.15	1.01	0.90
Production cost equity volumes (NOK/boe, last 12 months)	**48**	49	44	42	42
Share information[1)]					
Diluted earnings per share NOK	**(11.8)**	6.87	12.50	21.60	24.70
Share price at Oslo Børs (Norway) on 31 December in NOK	**123.70**	131.20	147.00	139.00	153.50
Dividend per share NOK [2)]	**7.62**	7.20	7.00	6.75	6.50
Dividend per share USD [2),3)]	**1.07**	0.97	1.15	1.21	1.08
Weighted average number of ordinary shares outstanding (in thousands)	**3,179,443**	3,179,959	3,180,684	3,181,546	3,182,113

1) See section 6 *Shareholder information* for a description of how dividends are determined and information on share repurchases. The board of directors will propose the total 2015 dividend for approval at the annual general meeting scheduled for 11 May 2016.

2) Proposed cash dividend for 2015. For 2015, the NOK amount covers first quarter while the USD amount is for second, third and fourth quarter. Figure presented for 2015 using the Central Bank of Norway 2015 year end rate for Norwegian kroner, which was USD 1.00 = 8.8090 NOK.

3) Figures presented using the Central Bank of Norway year end rate for Norwegian kroner.

4) Total revenues and other income for 2013 and 2012 are restated.

2 Strategy and market overview

The profitability of the oil and gas industry continues to be challenged and Statoil's financial results in 2015 were influenced by the fall in oil prices. Stricter project prioritisation and a comprehensive efficiency programme are showing progress and are expected to continue to improve cash flow and profitability. Statoil proposes to the annual general meeting a scrip dividend from the fourth quarter of 2015. Statoil's strong financial position provides a firm basis on which to balance capital investment and dividends to shareholders, which Statoil expects to grow in line with its long-term earnings.

Last year Statoil outlined plans to further strengthen its competitiveness, and is now reinforcing its effort and commitment to deliver on priorities of high value creation, increased efficiency and competitive shareholder returns. Through Statoil`s flexibility in its investment programme Statoil believes that it is well prepared for potential sustained market volatility and uncertainty.

Statoil's ambition to further reduce costs and improve efficiency was presented at the capital markets update (CMU) on 6 February 2015. Then, the company announced that it was targeting annual savings of USD 1.7 billion from 2016 (pre-tax) as measured against the cost base of 2013. Having already realised $1.9 billion in savings (pre-tax), Statoil announced a new goal at the CMU on 4 February 2016. The company will step up its efficiency programme by 50% with a goal to realise USD 2.5 billion in annual savings from 2016 (pre-tax), again as measured against the cost base of 2013. The step-up of $0.8 billion is expected to be divided by two-thirds capital expenditures (capex) and one-third operational expenditures (opex).

Improvement programmes are Statoil's response to the industrial challenges characterised by high costs and declining returns. More specifically, the ambition is to realise positive production effects and cost savings to improve Statoil's financial results and cash-flows.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. See section 10 *Forward-Looking Statements* for more information.

2.1 Statoil's business environment

2.1.1 Market overview

Global economic GDP growth eased in 2015, to 2.4% from 2.6% in 2014. This largely reflects weakness in non-OECD economies where activity decelerated over the year. Growth in OECD, on the other hand, held up relatively well at around 2%, supporting overall economic growth and energy demand.

The underlying fundamentals of the United States economy remain sound and GDP growth ticked up slightly to 2.5% in 2015 from 2.4% in 2014. GDP growth also accelerated nominally in the Eurozone to 1.5%, supported by low energy prices, reduced fiscal headwinds, more monetary stimulus and a weak euro. UK GDP growth slowed in 2015, but remains decent at 2.4%, whereas Japan barely avoided its fourth recession in five years. Growth in emerging countries slipped to 3.6% in 2015, reflecting both weakness in commodity prices and domestic challenges. Deep recessions have emerged in Brazil and Russia, whilst China continues on an intended path of gradual deceleration and consequent structural reforms. Net commodity importers such as India are doing much better, and India's GDP growth rate outpaced China's in 2015.

Several major forces are at play in the global economy and will continue to affect demand, including soft commodity prices and persistently low interest rates, increasingly divergent monetary policies across major economies, and weak world trade. In particular, the sharp decline in oil prices since mid-2014 has supported global economic activity and is expected to continue to do so in 2016.

Global oil demand grew by a healthy 1.6 mmbbl per day in 2015, driven by a colder than normal winter in the US and Northern Europe and the lower prices of crude oil. Demand growth in absolute terms was highest in China, despite 2015 being a challenging year for Chinese stock markets and the Chinese economy in general. Non-Opec producers have proven to be resilient to lower prices and grew production by 1.3 mmbbl per day in 2015 while Opec added 1.1 mmbbl per day to their production, mainly from Saudi Arabia and Iraq. This has postponed the rebalancing between supply and demand and has led to a continued drop in oil prices.

2015 saw moderate growth in gas supply and demand of 1.5%, which is below the growth rates of the previous years. The United States is the main driver behind the growth. Europe experienced a weather-driven increase in demand as compared to 2014. Gas consumption declined in Japan and South Korea due to weak power sector gas demand caused by the (re)start of coal and nuclear power plants. Gas demand growth slowed in China and other emerging markets, with more competitively priced oil products being one contributing factor. In the United States, a multi-year wave of gas supply growth came to an end in 2015, but demand could not keep up with supply growth, and prices fell. A strong supply of pipeline gas to Europe and an emerging oversupply of LNG have further depressed gas prices.

The global economic situation continues to be fragile, with development partly driven by uncertain political environments in key countries and regions, in addition to normal supply and demand factors. The situation at the end of 2015, with high storage levels and low prices, will continue to put pressure on international oil companies to increase efficiency and reduce costs. This will contribute to a gradual rebalancing of markets for oil and gas. The impact of this on price levels and price developments is very uncertain.

2.1.2 Oil prices and refining margins

High volatility characterised the oil market in 2015, with the price of Brent in a range between USD 66 per barrel in May to USD 35 per barrel at the end of December. Refinery margins were well above normal levels due to low crude prices throughout the year.

Oil prices

The average price for dated Brent crude in 2015 was USD 53/bbl, down 47% from 2014. The price was at USD 55/bbl in the beginning of 2015, on a downward trajectory. A temporary low was reached at just above USD 45/bbl in the middle of January before the prices started climbing again. A positive market sentiment drove the price of dated Brent up in the second quarter. Signs of a downturn in the Chinese economy and the nuclear deal between P5+1 and Iran contributed to a declining market sentiment and prices fell again to a new low in August. The price of dated Brent recovered somewhat again in the 3rd quarter and in to the 4th quarter, before the 168th Opec meeting on the 4th of December. No action was agreed by the Opec member countries and the price of Brent went below USD 40/bbl for the first time since the spring of 2009. The dated Brent price was USD 36/bbl on 31 December 2015, a year-end level not seen for a decade. The futures market for Brent at the Intercontinental Exchange (ICE) was in contango throughout 2015. See section 9 *Terms and definitions* for further details.

Although the conflict level in Syria increased further and the armed conflict in Yemen added tension in the Middle East, geopolitical events had less effect on the crude oil prices in 2015, compared with the previous year.

Opec's decision, in late 2014, to not balance the market, marked the change of a 30-year old strategy. Subsequent to this the oil market was highly volatile throughout 2015, while the participants endeavoured to find the new price level of crude oil. Although oil demand increased by 1.6 mmbbl per day, much due to a cold winter and low prices, the market remained oversupplied throughout the whole year, with total supply growth of 2.4 mmbbl per day of production. As a consequence, the global oil stocks were at historically high levels by year-end.

2015 was an eventful year for North American (NA) crude. The price of US WTI crude, as quoted at the Cushing tank farm in Oklahoma, averaged USD 49/bbl in 2015, down 47% from 2014. The price of WTI was USD 53/bbl at the beginning of the year. On 31 December 2015 the WTI price was at USD 37/bbl, roughly at par with first month Brent. With low crude prices through 2015, rig counts have dropped and production growth has faltered. At the same time, crude inventories have continued to grow, further weighing on crude prices. New pipeline and crude distillation capacity, coupled with slower production growth, have created a tighter balance for US light crude, easing the large price discounts of inland crudes relative to Brent. The easing of discounts has challenged the economics of more expensive transport solutions such as rail relative to pipeline, such that crude by rail loadings have declined dramatically during 2015. In late 2015, the US government passed legislation allowing unrestricted export of crude oil for the first time since the 1970s. While little impact is expected in the global market short term, given the current oversupplied global crude market, unrestricted US crude exports provides producers with greater access to higher value global crude markets and could impact price differentials.

Refining margins

Refinery margins in Northwest Europe, as calculated against dated Brent crude, were well above normal in 2015. One reason for the strength was the weak crude oil market, with dated Brent priced below the first forward month at the ICE exchange throughout the year. Further, the price differentials vs. Brent for the crude oils actually used were lower than last year. The other main factor was a very strong gasoline market. Low price levels at the pump led to rising demand in the US, and gasoline demand in Europe stopped falling. Changes to the Chinese economy led to more emphasis on the consumer sector. New car sales in China almost matched that of the US, and some 80% were net additions to the fleet. Chinese gasoline demand therefore rose almost as much as in the US, and strong growth was also seen in India and Pakistan. This demand growth led to capacity constraints at refineries, in particular for high-octane components. Europe, being in net surplus on gasoline, was able to export more into these markets, with parts of it going as high-octane components at strong price premiums. For naphtha, which is a feedstock both for the petrochemical industry and for making gasoline, Asian demand for imports from Europe rose through the year and gave very strong margins here. On the other hand, new refineries in Asia and the Middle East were geared towards diesel production. New diesel volumes exported to Europe led to rising inventory levels here, despite a quite strong demand growth. The situation became dramatic in the fourth quarter of 2015, when high refinery throughputs in order to make enough gasoline and naphtha led to excess diesel production. This made diesel tanks go full and the diesel margin decreased. LPG was oversupplied due to high exports from the US. Heavy fuel oil was oversupplied due to declining demand. However, against the low Brent crude oil prices, both products still saw quite normal margins.

2.1.3 Natural gas prices

Natural gas prices fell during 2015 in most markets. European gas prices reached the lowest level since early 2010. Reasons include weak demand, good supplies and low prices for coal, oil and other competing fuels. Henry Hub gas prices in the United States also declined during 2015, and the prices at year-end were at the lowest level since the 1990s.

Gas prices - Europe
European gas market prices averaged USD 6.5/mmBtu in 2015, down 20% from 2014. EU gas consumption for heating purposes recovered in 2015 as temperatures returned to more normal levels after a particularly mild winter in 2014. The use of gas for power generation increased in Southern Europe due to high summer temperatures, but declined in other parts of Europe. High availability of wind in 2015 and a steady growth in renewable generation capacity made inroads in the overall need for gas-fired and other thermal power plants in Europe.

Norwegian exports of pipeline gas reached record-levels of 108 bcm in 2015. EU indigenous gas production fell by 10% to 125 bcm as the Dutch government lowered existing production caps at the large Groningen field as a response to earthquake activity. Russia exported more than 150 bcm of pipeline gas to Europe in 2015, close to recent historical highs. Europe imported around 50 bcm LNG in 2015, more than in 2014, but still 35 bcm below the peak a few years ago.

Gas prices - North America
First quarter prices centered on USD 3/mmBtu, while second and third quarter prices fluctuated around USD 2.75/mmBtu, with weather-related ups and downs. However, in the fourth quarter prices fell and reached USD 1.50/mmBtu at the end of the year, as storage rose to new record highs and an El Niño weather event quashed demand in the winter peak season. As a result, the Henry Hub average of USD 2.6/mmBtu was the lowest annual price in over a decade, down from USD 4.4/mmBtu in 2014.

US gas producers responded to the falling prices by withdrawing rigs. Gas production peaked at the end of the summer and supply has been falling since. Demand for gas was strong in 2015, with natural gas for the first time exceeding coal use in the power sector for most of the year.

Global LNG prices
Global prices for LNG have plummeted. Prices under long-term LNG contracts to buyers in Asia are tracking oil prices with a lag, and contract prices were typically down 40% from 2014. The price assessment for spot LNG cargoes in Asia reached USD 7.5/mmBtu over the year compared to USD 14/mmBtu in 2014. LNG prices are now back to levels prior to the Fukushima nuclear disaster in March 2011. The global LNG market has entered a period where the growth of supplies from Australian, US and other liquefaction projects could exceed demand.

2.2 Statoil's corporate strategy

Statoil creates value by accessing, exploring, developing, and producing energy sources globally, and by enhancing the value of such production through its mid- and downstream positions.

Fundamental changes are happening in the oil and gas industry. The industry faces new challenges, such as increased pressure on margins, changing patterns of energy supply and consumption, geopolitical instability and rising climate change concerns.

Statoil's top priorities remain to conduct safe and reliable operations with zero harm to people and the environment, and to grow value through disciplined investments and prudent financial management with competitive redistribution of capital to shareholders. To succeed going forward in turning Statoil's vision into reality, Statoil pursues a strategy that will:
- Deepen and prolong Statoil's NCS position
- Grow material and profitable international positions
- Pursue focused and value-adding mid- and downstream activities
- Provide energy for a low carbon future

In addition, Statoil will research, develop, and deploy technology to create opportunities and enhance the value of Statoil's current and future assets.

Deepen and prolong Statoil's NCS position

For more than 40 years, Statoil has explored, developed and produced oil and gas from the Norwegian continental shelf (NCS). Statoil aims to deepen and prolong its position by accessing and maturing opportunities into valuable production. At the same time Statoil plans to improve the reliability and lifespan of fields already in production.

- **Exploration:** Statoil has proven to be a committed NCS explorer across mature, growth, and frontier areas. In the last year, Statoil participated in 21 completed exploration wells of which 10 were discoveries. Statoil announced discoveries in the Aasta Hansteen area, the Krafla area, and the King Lear area. Statoil applied for new acreage in the Barents Sea as part of the 23rd licensing round and entered the Barents Sea Exploration Collaboration with four other oil and gas explorers to address common operational challenges. Statoil also applied for additional NCS licenses during the 2015 Awards in Predefined Areas (APA) with the results awarded in 2016
- **Development:** Statoil received approval from the Norwegian Ministry of Petroleum and Energy for the plan for development and operation (PDO) for Johan Sverdrup Phase I and awarded several related key contracts to suppliers. The development plan for Johan Sverdrup Phase II, along with other projects, continues to be matured. In 2015, Statoil delayed the concept selection for Johan Castberg, Snorre 2040 and Trestakk (sanctioned early 2016) to secure robust development solutions. Gina Krog's expected start-up is now 2017 with the steel jacket having been installed and predrilling of the production wells started
- **Production:** Statoil began production from Valemon, Oseberg Delta 2, Gullfaks South Oil, Smørbukk South Extension and the Lundin-operated Edvard Grieg field. Three major projects to increase recovery have been delivered in 2015; at Troll A two new gas compressors were installed, the Åsgard subsea compression, the world's first subsea gas compression plant, came on stream, and the world's first subsea wet gas compressor is nearing completion at Gullfaks

Statoil made further portfolio adjustments to improve its NCS position. Statoil increased its share in the Alfa Sentral project, which straddles the border of the NCS and UK continental shelf (UKCS). Statoil's equity share now stands at 24% in licence P312 on the UKCS and 62% in licence PL046 on the NCS (Statoil-operated); the two licenses together comprise the Alfa Sentral field. Statoil also farmed down in the Gudrun field. Statoil remains the operator of the field.

The target to reduce CO_2 emissions on the NCS was increased to 1.2 million tonnes by 2020, which is up 50% from the initial target of 800,000 tonnes. The initial target was set in 2008 and is expected to be reached in 2016.

Grow material and profitable international positions

International oil and gas production represents approximately 37% of Statoil's equity production and now stands at 739 kboe/d. Statoil will continue to explore, develop, and produce oil and gas opportunities outside Norway to enhance Statoil's upstream portfolio.

- **Exploration:** Statoil is an active international explorer for oil and gas. In the last year, Statoil participated in 18 completed exploration wells of which eight were discoveries. Statoil focused in Canada, Tanzania, Brazil, the UK and the US Gulf of Mexico. Statoil announced a gas discovery in Tanzania (Mdalasini-1). Statoil accessed new acreage in Canada, New Zealand, Indonesia, Mozambique, Russia, and the US Gulf of Mexico, and entered three new countries, Nicaragua, South Africa, and Uruguay. Government approval is pending for the newly acquired acreage in Mozambique, South Africa, and Uruguay. Statoil exited both our operated and non-operated licenses in the Chukchi Sea (Alaska). Statoil also closed its office in the Faroe Islands following the relinquishment of our exploration acreage
- **Development:** In Europe, the partner-operated Corrib gas field in Ireland came on stream at the end of 2015; meanwhile, Statoil postponed the Mariner field's start-up date to 2018. In the US Gulf of Mexico, the partner-operated Heidelberg project entered its final stages in 2015 as it prepared for first oil in early 2016, meanwhile Big Foot was postponed due to technical challenges in the final project stage
- **Production:** Production has steadily increased from fields such as CLOV in Angola and Jack/St. Malo in the US Gulf of Mexico. In the US, further optimisation of the onshore portfolio targeting cost improvements has been on-going, including the reorganisation of some of the activities to extract greater synergies

Statoil made further portfolio adjustments to improve its international exploration portfolio. Statoil sees value in gaining operatorships, and in 2015 Statoil became the operator in BM-C-33 offshore Brazil, which contains the Pão de Açúcar, Seat, and Gávea discoveries. Statoil also completed an agreement to reduce Statoil's average working interest in Statoil's non-operated US southern Marcellus onshore asset from 29% to 23%. In another transaction, Statoil acquired an additional 13% interest in Statoil's Eagle Ford joint venture and became its sole operator.

Pursue focused and value-adding mid- and downstream activities

The prime objective for Statoil's mid- and downstream activities is to process and transport its oil and gas production (including the Norwegian State's petroleum) competitively to premium markets, securing maximum value realisation. The priorities are:

- High regularity in midstream operation and continuous improvement within HSE, efficiency and costs
- Market Statoil's equity production (crude oil, natural gas, related products) and the State's Direct Financial Interest (SDFI) volumes for maximum value creation
- Develop the Asset Backed Trading model across commodities
- Maintain the position as a leading European gas supplier
- A capital lean asset structure

Strategic focus is directed at optimising the value of Statoil's flexible Norwegian gas production assets that supply Europe and Statoil's midstream activities in North America, where Statoil's onshore un-conventionals portfolio is progressing and where margin capture is important. Statoil achieved strong trading results across all commodities and robust refinery results through good margins, cost reductions and high availability.

Strategic progress in Statoil's mid- and downstream portfolio has been made in 2015. Export pipelines for the Utsira High and the Norwegian Sea (Polarled) were installed. Statoil agreed to divest its 20% stake in the Trans Adriatic Pipeline AG in 2015 following earlier divestments in 2014.

Providing energy for a low carbon future

Statoil recognises that opportunities are increasingly available in producing low carbon energy. In 2015, Statoil created a new business area, New Energy Solutions, to further access, develop, and produce low carbon energy when and where it is deemed valuable.

- **Development:** In the 4th quarter 2015, Statoil sanctioned Hywind Scotland Offshore Floating Test Park in Scotland; Statoil's ownership share is 100%. The park will have a total installed capacity of 30 MW and planned production start-up is 2017. The Dudgeon Offshore Wind Park sanctioned in 2014 is progressing as planned towards start-up in 2017; Statoil's ownership share is 35%. The park will have a total installed capacity of 402 MW. The Forewind consortium, comprising Statoil, Statkraft, RWE and SSE, all with a 25% owner stake, continues to mature projects and has received consent for four 1.2 GW projects in the Dogger Bank Area off the UK east coast
- **Production:** Statoil is a non-operating partner in the Scira consortium (40% owner stake) which produces electricity from the Sherringham Shoal wind park in the UK. The park has an installed capacity of 317 MW

Research, development, and deployment of technology to unlock opportunities and enhance value

Statoil believes that technology is a critical success factor in the current business environment. Statoil's technology development activities aim to reduce field development, drilling and operating costs, and CO_2 and other greenhouse gas emissions. Statoil's technology efforts focus on the following priority areas:

- **Business-critical technologies**: Upstream technologies are prioritised, primarily in the areas of Exploration, Reservoir, Drilling and Well and Subsea production systems. Statoil's main focus has been on cost reduction, for example further development of the steerable drilling liner system to reduce well construction costs
- **Strengthening Statoil's licence to operate**: Statoil's commitment to sustainability continues. Statoil's ongoing "Powering collaboration" agreement with GE aims to accelerate the development of more sustainable energy solutions by addressing CO_2 and methane emissions, water usage and energy optimisation of operations. Statoil is also addressing energy efficiency of operating assets by, e.g. implementing on-line water wash systems on gas turbines
- **Expanding Statoil's capabilities**: Statoil's technical capabilities are expanding to meet the challenges of the New Energy Solutions business area for renewable and low carbon energy solutions. Technology development is conducted in-house, in collaboration with suppliers and through venture activities. A key technological focus area is finding more efficient ways of producing clean energy, particularly by reducing costs in the areas of construction and maintenance for both fixed and floating offshore wind applications

2.3 Group outlook

Statoil's plans address the current environment while continuing to invest in high-quality projects. Statoil continues to reiterate its efforts and commitment to deliver on its priorities of high value creation, increased efficiency and competitive shareholder return.

- Organic capital expenditures for 2016 (i.e. excluding acquisitions, capital leases and other investments with significant different cash flow pattern) are estimated at around USD 13 billion
- Statoil intends to continue to mature the large portfolio of exploration assets and estimates a total exploration activity level of around USD 2 billion for 2016, excluding signature bonuses
- Statoil aims to deliver efficiency improvements with pre-tax cash flow effects of around USD 2.5 billion annually from 2016
- Statoil's ambition is to keep the unit of production cost in the top quartile of Statoil`s peer group
- For the period 2014 - 2017, organic production growth [7] is expected to come from new projects resulting in around 1% CAGR (Compound Annual Growth Rate) from a 2014 level rebased for divestments
- The equity production for 2016 is estimated to be somewhat lower than the 2015 level [7]
- Scheduled maintenance activity is estimated to reduce quarterly production by approximately 25 mboe per day in the first quarter of 2016 of which the majority is liquids internationally. In total, the maintenance is estimated to reduce equity production by around 60 mboe per day for the full fiscal year 2016, which is higher than the 2015 impact
- Indicative effects from Production Sharing Agreement (PSA-effect) and US royalties are estimated to be around 135 mboe per day in 2016 based on an oil price of USD 40 per barrel and 165 mboe per day based on an oil price of USD 70 per barrel [4]
- Deferral of production to create future value, gas off-take, timing of new capacity coming on stream and operational regularity represent the most significant risks related to the production guidance
- The board of directors proposes to the annual general meeting (AGM) maintaining a dividend of USD 0.2201 per share for the fourth quarter 2015 and to introduce a two-year scrip dividend programme for eligible shareholders starting from the fourth quarter 2015
- With effect from first quarter of 2016, Statoil will change to USD as presentation currency

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. For further information see section 10 *Forward-Looking Statements*.

3 Business overview

3.1 Our history

Statoil was formed in 1972 by a decision of the Norwegian parliament and listed on the stock exchanges in Oslo and New York in 2001.

Statoil was incorporated as a limited liability company under the name Den norske stats oljeselskap AS on 18 September 1972. As a company wholly owned by the Norwegian State, Statoil's role was to be the government's commercial instrument in the development of the oil and gas industry in Norway.

In 2001, the company became a public limited company listed on the Oslo and New York stock exchanges, and it changed its name to Statoil ASA.

Statoil has grown in parallel with the Norwegian oil and gas industry, which dates back to the late 1960s. Initially, Statoil's operations were primarily focused on exploration, development and production of oil and gas on the Norwegian continental shelf (NCS), as a partner.

In the 1970s, Statoil commenced its own operations, made important discoveries and began oil refining operations, which have been of great importance to the further development of the NCS.

Statoil grew substantially in the 1980s through the development of large fields on the NCS (Statfjord, Gullfaks, Oseberg, Troll and others). Statoil also became a major player in the European gas market by securing large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, Statoil was involved in manufacturing and marketing in Scandinavia and established a comprehensive network of service stations.

Since 2000, our business has grown as a result of substantial investments on the NCS and internationally. Our ability to fully realise the potential of the NCS was strengthened through the merger with Hydro's oil and gas division on 1 October 2007.

In recent years, Statoil has utilised their expertise to design and manage operations in various environments in order to grow our upstream activities outside our traditional area of offshore production. This includes the development of heavy oil and shale gas projects.

In 2010, Statoil carried out an initial public offering of Statoil Fuel & Retail ASA on the Oslo Børs, partially divesting and reducing our interest in the business relating to service stations. In 2012, all of the remaining shares in Statoil Fuel & Retail ASA were divested.

Statoil also participates in projects that focus on other forms of energy, such as offshore wind and carbon capture and storage, in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

3.2 Our business

Statoil is a technology-driven energy company primarily engaged in oil and gas exploration and production activities.

Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian Public Limited Liability Companies Act. The Norwegian State is the largest shareholder in Statoil ASA, with a direct ownership interest of 67%.

Statoil's head office is located in Stavanger, Norway. Statoil has business operations in more than 30 countries and employs about 21,600 employees worldwide.

Statoil is the leading operator on the Norwegian continental shelf (NCS) and also has substantial international activities. Statoil is present in several of the most important oil and gas provinces in the world. In 2015, 37% of Statoil's equity production came from international activities and the company also holds operatorships internationally.

Our access to crude oil in the form of equity, governmental and third party volumes makes Statoil a large net crude oil seller, and Statoil is the second-largest supplier of natural gas to the European market. Processing and refining are also part of our operations. Statoil is also participating in projects that focus on other forms of energy, such as offshore wind and carbon capture and storage, in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

Statoil's business address is Forusbeen 50, N-4035 Stavanger, Norway. Its telephone number is +47 51 99 00 00.

3.3 Our competitive position

There is intense competition in the oil and gas industry for customers, production licences, operatorships, capital and experienced human resources.

Statoil competes with large integrated oil and gas companies, as well as with independent and state-owned companies, for the acquisition of assets and licences for the exploration, development and production of oil and gas, and for the refining, marketing and trading of crude oil, natural gas and related products. Key factors affecting competition in the oil and gas industry are oil and gas supply and demand, exploration and production costs, global production levels, alternative fuels, and environmental and governmental regulations. In addition, Statoil competes to develop wind energy opportunities.

Statoil's ability to remain competitive will depend, among other things, on the company's management continuing to focus on reducing unit costs and improving efficiency, and maintaining long-term growth in reserves and production through continuing technological innovation. It will also depend on our ability to seize international opportunities in areas where our competitors may also be actively pursuing exploration and development opportunities. Statoil believes it is in a position to compete effectively in each of our business segments.

The information about Statoil's competitive position in the business overview and strategy, and operational review sections, is based on a number of sources. They include investment analyst reports, independent market studies, and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

Statoil has endeavoured to be accurate in our presentation of information based on other sources, but has not independently verified such information.

Improvement programmes

Statoil's ambition to further reduce cost and improve efficiency was presented at the capital markets update (CMU) on 6 February 2015, targeting annual savings of USD 1.7 billion from 2016. At the CMU on 4 February 2016, Statoil announced that it will step up its efficiency programme by 50% with a goal to realise USD 2.5 billion in annual savings from 2016.

Improvement programmes are Statoil's response to the industrial challenge characterised by reducing prices for our products, escalating cost and declining returns. More specifically, the ambition is to realise positive production effects and capex and operating cost savings to improve financial results and cash-flows.

3.4 Corporate structure

Statoil's operations are managed through the following business areas:

Development and Production Norway (DPN)

DPN comprises our upstream activities on the Norwegian continental shelf (NCS). DPN aims to continue its leading role and ensure maximum value creation on the NCS. Through excellent HSE and improved operational performance and cost, DPN strives to maintain and strengthen Statoil's position as a world-leading operator of producing offshore fields. DPN seeks to open new acreage and to mature improved oil recovery and exploration prospects. New and existing fields are primarily developed using an industrial approach, in which speed of delivery and cost improvements through standardisation and repeated use of proved solutions are key elements.

Development and Production International (DPI)

DPI comprises our worldwide upstream activities that are not included in the DPN and Development and Production USA (DPUSA) business areas. DPI's ambition is to build a large and profitable international production portfolio comprising activities ranging from accessing new opportunities to delivering on existing projects and managing a production portfolio. DPI endeavours to ensure the delivery of profitable projects in a range of complex technical and stakeholder environments, and it manages a broad non-operated production portfolio that will be complemented with operated positions.

Development and Production United States (DPUSA)

DPUSA comprises our upstream activities in the USA and Mexico. DPUSA's ambition is to develop a material and profitable position in the US and Mexico, including the deep water regions of the Gulf of Mexico and unconventional oil and gas in the US. In this connection, Statoil aims to further strengthen its capabilities in deep water and unconventional oil and gas operations.

Marketing, Midstream and Processing (MMP)

MMP comprises our marketing and trading of oil products and natural gas, transportation, processing and manufacturing, and the development of oil and gas value chains. MMP's ambition is to maximise value creation in Statoil's midstream, marketing and renewable energy business.

Technology, Projects and Drilling (TPD)

TPD's ambition is to provide safe, efficient and cost-competitive global well and project delivery, technological excellence, and research and development. Cost-competitive procurement is an important contributory factor, although group-wide procurement services are also expected to help to drive costs in the group down.

Exploration (EXP)
EXP's ambition is to position Statoil as one of the leading global exploration companies. This is achieved through accessing high potential new acreage in priority basins, globally prioritising and drilling more significant wells in growth and frontier basins, delivering near-field exploration on the NCS and other select areas, and achieving step-change improvements in performance.

New Energy Solutions (NES)
NES reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. NES is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Global Strategy and Business Development (GSB)
GSB sets the corporate strategy, business development and merger and acquisition (M&A) activities for Statoil. The ambition of the GSB business area is to closely link corporate strategy, business development and M&A activities to actively drive Statoil's corporate development.

Reporting segments
Statoil reports its business in the following reporting segments: Development and Production Norway (DPN); Development and Production International (DPI), which combines the DPI and DPUSA business areas; Marketing, Midstream and Processing (MMP); and Other.

The Other reporting segment includes activities in New Energy Solutions (NES), Technology, Projects and Drilling (TPD), Global Strategy and Business Development (GSB) and Corporate staffs and support functions. Activities relating to the Exploration (EXP) business area are allocated to, and presented in, the respective development and production segments.

Presentation
In the following sections, the operations of each reporting segment are presented. Underlying activities or business clusters are presented according to how the reporting segment organises its operations. The Exploration business area's activities, which include group discoveries and the appraisal of new exploration resources, are presented as part of the various development and production reporting segments (Development and Production Norway, and Development and Production International).

As required by the SEC, Statoil prepares its disclosures about oil and gas reserves and certain other supplementary oil and gas disclosures based on geographical areas. The geographical areas are defined by country and continent. They consist of Norway, Eurasia excluding Norway, Africa, and the Americas.

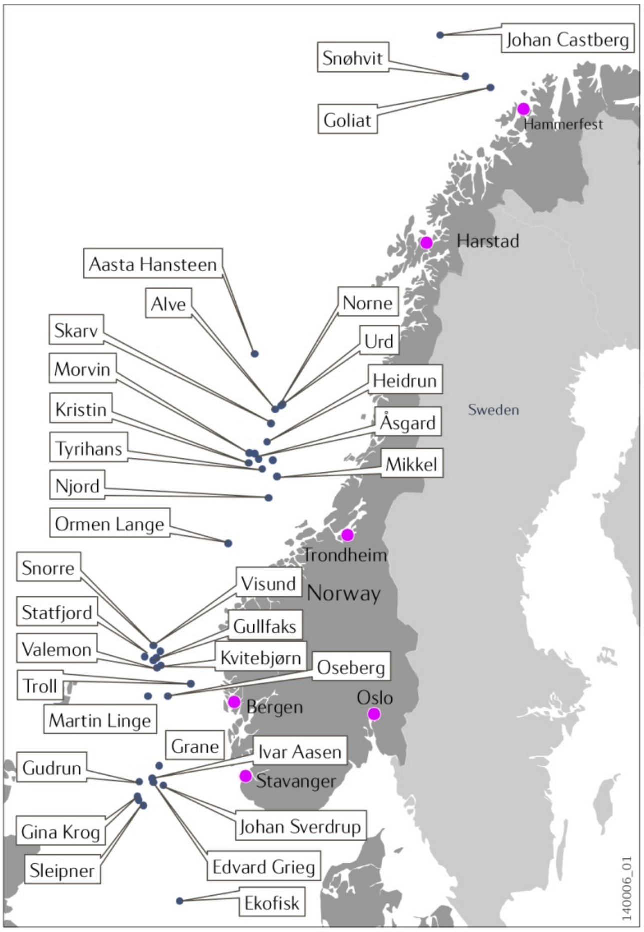
See note 3 *Segments* in the Consolidated financial statement for more details.

3.5 Development and Production Norway (DPN)

3.5.1 DPN overview

Development and Production Norway (DPN) is responsible for field development and operational activities on the Norwegian continental shelf (NCS).

Statoil's equity and entitlement production on the NCS was 1,232 mboe per day in 2015. That was about 68% of Statoil's total entitlement production and 62.5% of Statoil's equity production.



DPN has organised the production operations into four business clusters: Operations North (Barents Sea) located in Harstad, Operations Mid-Norway (Norwegian Sea) located in Stjørdal near Trondheim, Operations West (North Sea) located in Bergen and Operation South (North Sea) located in Stavanger. Partner-operated fields cover the entire NCS and are internally included in the Operations South business cluster.

When possible, the fields in each cluster use common infrastructure, such as production installations and oil and gas transport facilities. This reduces the investments required to develop new fields. DPN's efforts in these core areas also focus on finding and developing smaller fields through the use of existing infrastructure and on increasing production by improving the recovery factor.

DPN is also working to extend production from our existing fields through improved reservoir management and the application of new technology.

Key events and portfolio developments in 2015:

- In January 2015, Statoil announced the start-up of production at the Valemon oil and gas field in the North Sea
- Statoil announced production start up on fast track projects at the Oseberg Delta in February, Gullfaks Sør Olje in July and Smørbukk Sør Extension in September
- In November the start up of production at the Edvard Grieg field was announced by Lundin
- The major redevelopment projects Åsgard Subsea compression and two new compressors on the Troll A platform have started up
- A total of seven turnarounds were planned to be performed during 2015. Four turnarounds were carried out, and three turnarounds were deferred from 2015 to 2016 to coordinate with other activities due to reduce production losses and reduce costs
- Plan for Development and Operations (PDO) for the Johan Sverdrup field and Gullfaks Rimfaksdalen Fast track project were approved by the Ministry of Petroleum and Energy (MPE) and the PDO for Oseberg Vestflanken 2 was submitted to the MPE
- An extensive exploration drilling program in 2015 resulted in 21 completed wells, of which 10 were discoveries. A total of 16 wells were Statoil operated
- Statoil has delivered an extensive application for the 23rd concession round and has been awarded interest in 24 licenses on the NCS in the Awards in Predefined Areas (APA) 2015, 13 of those as operator and 11 as partner
- In December Statoil announced that it farmed down to Repsol a 15% interest in the Gudrun field. Statoil remains as operator and largest equity holder with a 36% interest

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by high costs and declining returns is addressed in the section 2 *Strategy and market overview*.

3.5.2 Fields in production on the NCS

Statoil's entitlement production at NCS was about 68% of Statoil's total entitlement production in 2015.

The following table shows DPN's average daily entitlement production of oil, including NGL and condensates, and natural gas for the years ending 31 December 2015, 2014 and 2013. Field areas are groups of fields operated as a single entity.

	For the year ended December 31,								
	2015			2014			2013		
Area production	Oil and NGL mbbl	Natural gas mmcm	mboe/day	Oil and NGL mbbl	Natural gas mmcm	mboe/day	Oil and NGL mbbl	Natural gas mmcm	mboe/day
Operations North	32	7	78	36	7	80	24	5	56
Operations Mid	113	17	218	126	17	235	126	15	222
Operations West	267	51	591	264	43	535	290	48	589
Operations South	134	13	214	107	11	177	94	12	167
Partner Operated Fields	50	13	132	55	16	157	58	20	182
Total	595	101	1,232	588	95	1,184	591	99	1,217

The following table shows the NCS production by fields and field areas in which Statoil was participating as of 31 December 2015.

Business cluster	Geographical area	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily production in 2015 mboe/day
Operations North						
Snøhvit	The Barents Sea	36.79	Statoil	2007	2035	47.1
Norne	The Norwegian Sea	39.10	Statoil	1997	2026	5.9
Alve	The Norwegian Sea	85.00	Statoil	2009	2029	10.6
Urd	The Norwegian Sea	63.95	Statoil	2005	2026	14.2
Total Operations North						77.9
Operations Mid-Norway						
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	92.1
Morvin	The Norwegian Sea	64.00	Statoil	2010	2027	16.3
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2020 [1)]	14.3
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	49.6
Kristin	The Norwegian Sea	55.30	Statoil	2005	2033 [2)]	24.5
Heidrun	The Norwegian Sea	13.04	Statoil	1995	2024 [3)]	8.7
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 [4)]	6.1
Hyme	The Norwegian Sea	35.00	Statoil	2013	2014 [5)]	6.2
Total Operations Mid-Norway						217.8
Operations West						
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030	185.2
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030	38.2
Fram	The North Sea	45.00	Statoil	2003	2024	16.9
Fram H Nord	The North Sea	49.20	Statoil	2014	2024	2.3
Oseberg	The North Sea	49.30	Statoil	1988	2031	86.4
Tune	The North Sea	50.00	Statoil	2002	2032 [6)]	1.9
Gullfaks	The North Sea	51.00	Statoil	1986	2036	69.4
Gimle	The North Sea	65.13	Statoil	2006	2034 [7)]	2.6
Kvitebjørn	The North Sea	39.55	Statoil	2004	2031	64.0
Valemon	The North Sea	57.76	Statoil	2015	2031	16.4
Visund	The North Sea	53.20	Statoil	1999	2034	48.5
Grane	The North Sea	36.66	Statoil	2003	2030	45.8
Volve	The North Sea	59.60	Statoil	2008	2028	10.0
Veslefrikk	The North Sea	18.00	Statoil	1989	2020 [8)]	3.1
Total Operation West						590.5
Operations South						
Sleipner Vest	The North Sea	58.35	Statoil	1996	2028	49.2
Sleipner Øst	The North Sea	59.60	Statoil	1993	2028	44.4
Gungne	The North Sea	62.00	Statoil	1996	2028	10.0
Gudrun	The North Sea	36.00	Statoil	2014	2028 [9)]	6.1
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026	42.6
Statfjord Øst	The North Sea	31.69	Statoil	1994	2026 [10)]	1.3
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026	1.2
Sygna	The North Sea	30.71	Statoil	2000	2026 [10)]	0.8
Snorre	The North Sea	33.28	Statoil	1992	2015 [11)]	35.6
Vigdis area	The North Sea	41.50	Statoil	1997	2024	14.6
Tordis area	The North Sea	41.50	Statoil	1994	2024	8.2
Total Operations South						214.0

Business cluster	Geographical area	Statoil's equity interest in %[1]	Operator	On stream	Licence expiry date	Average daily production in 2015 mboe/day
Partner Operated Fields						
Ormen Lange	The Norwegian Sea	25.35	Shell	2007	2041 [12]	47.8
Skarv	The Norwegian Sea	36.17	BP Norge AS	2013	2033 [13]	46.8
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	14.3
Marulk	The North Sea	50.00	Eni Norge AS	2012	2025	13.2
Vilje	The North Sea	28.85	Marathon Oil	2008	2021	4.0
Sigyn	The North Sea	60.00	ExxonMobil	2002	2022	3.8
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	1.7
Edvard Grieg	The North Sea	15.00	Lundin Norway AS	2015	2035	0.4
Total Partner Operated Fields						131.9
Total						1,232.0

1) PL092 expires in 2020 and PL121 expires in 2022.
2) PL134B expires in 2027 and PL199 expires in 2033.
3) PL095 expires in 2024 and PL124 expires in 2025.
4) PL107 expires in 2021 and PL132 expires in 2023.
5) PL348 expires in 2029.
6) PL034 expires in 2020. PL053 expires in 2031 and PL190 in 2032.
7) PL120B expires in 2034 and PL050DS expires in 2023.
8) PL052 expires in 2020 and PL053 in 2031.
9) The 2015 Statoil farm down transaction with Repsol completed 31 December 2015 (From ownership 51% to 36% at Gudrun field)
10) PL037 expires in 2026 and PL089 expires in 2024.
11) PL089 expires in 2024 and PL057 expires in 2016.
12) PL209/250 expires in 2041 and PL208 expires in 2040.
13) PL212/262 expires in 2033 and PL159 expires in 2029.

The following sections provide information about the main producing assets. See section 4.1.4 *DPN profit and loss analysis* for a discussion of results of operations for 2015, 2014 and 2013.

3.5.2.1 Operations North

The main producing fields in the Operations North area are Snøhvit and Norne.

The Norwegian Sea region is characterised by petroleum reserves located at water depths between 340 and 380 metres. In the Barents Sea the petroleum reserves are located at water depths between 310 and 340 meters. The Gulf Stream keeps the sea free of ice all year round, but winter storms can make surface installations difficult to operate.

Snøhvit was the first field developed in the Barents Sea. It is one of the first major developments using onshore production facilities. All offshore installations are subsea. The natural gas is transported to shore and then processed at our Liquefied Natural Gas (LNG) plant on Melkøya. The LNG are shipped to customers in Europe, Asia, North and South America in tankers. The CO_2 in the feed-gas from Snøhvit and Albatross is removed due to freezing constraints in the process system. To reduce carbon dioxide emissions to the air the removed CO_2 is liquefied, transported through a pipeline, and then injected into a storage reservoir in Snøhvit. The LNG plant has produced according to plan in 2015, with high production efficiency, improved HSE results and enhanced cost efficiency. As of 1 January 2016 responsibility for operation of Snøhvit onshore facilities is transferred from DPN to MMP.

Norne is an oil field in the Norwegian Sea. The field has been developed using a floating production, storage and offloading vessel (FPSO) connected to subsea templates. Alve, Marulk, Urd and Skuld are tie-in fields connected to the Norne FPSO.

3.5.2.2 Operations Mid-Norway

The main producing fields in the Operations Mid-Norway area are Åsgard, Kristin, Tyrihans and Heidrun.

Operation Mid-Norway operates in a mature part of the Norwegian Sea, and is a significant contributor to Statoil's equity production. Main focus is to capitalise existing fields through profitable realisation of increased oil recovery and successful implementation of new developments. There is still exploration potential in the area and a targeted exploration effort is in execution.

The **Åsgard** field includes the Åsgard A production and storage ship for oil, the Åsgard B semi-submersible floating production platform for gas, and the Åsgard C storage vessel for condensate. In September 2015 Statoil started the world first subsea gas compressor on Åsgard. The compressor increases the Åsgard recovery rate from 67% to 87% thereby extending the reservoirs' productive lives. Mikkel and Morvin are tie ins to Åsgard.

Tyrihans is a subsea field with five templates. The well stream of oil and gas is tied back to Kristin for processing. Tyrihans receives seawater injection from Kristin and gas injection from Åsgard B.

Kristin is a gas and condensate field. The Kristin development is the first high-temperature/high-pressure (HTHP) field developed with subsea installations. The pressure and temperature in the reservoir are among the highest of all developed fields on the NCS.

Heidrun is developed with a floating concrete tension leg platform. The oil is transferred to the floating storage unit, Heidrun B, operated from June 2015.

The **Njord** field is located in the Norwegian Sea and the field has been developed with a floating steel platform unit, Njord A, with both drilling and processing facilities. The subsea field Hyme is tied back to Njord A.
As a result of structural integrity issues Njord A was temporarily shut down and extensive reinforcement work was completed through a long turnaround period from Sept 2013 to July 2014. Since July 2014 conditional monitoring and precautionary evacuation in forecasted bad weather conditions have been applied. In addition there is no drilling activity. The Project "Njord Future" is established to secure long term production for both the Njord and Hyme fields and to act as a tie-in host candidate for discoveries in the area.

3.5.2.3 Operations West

The main producing fields in the Operations West area are Troll, Oseberg, Gullfaks, Kvitebjørn, Visund and Grane

Operation West produces approximately half of Statoil's equity production in Norway. Its main focus is prolonging and increasing production through increased oil recovery, exploration and new field developments.

Troll is the largest gas field on the NCS and a major oil field. The Troll field is split into three hydrocarbon-bearing regions connected to three platforms: Troll A, B and C. The Troll gas is mainly exported and produced at the Troll A platform, while oil is mainly produced at Troll B and C. Fram and Fram H Nord are tie-ins to Troll C.

In October 2015 Troll A finalised the third and fourth pre-compressor project as described in the original PDO for the Troll field. The purpose of the project is to increase gas production by installing two extra pre-compressors on the Troll A platform.

The **Oseberg** area includes the Oseberg Field Centre, Oseberg C, Oseberg East and Oseberg South production platforms. Oil and gas from the satellites are transported in pipelines to the Oseberg Field Centre for processing and transportation.

The Delta2 facilities project on Oseberg Field Center was completed in 2015. Drilling operations related to the project have been on-going throughout 2015 and were finalised in January 2016. The Vestflanken2 project at Oseberg Field Center was sanctioned December 2015 with drilling to be performed by the Cat-J rig on the new unmanned wellhead platform, both under construction, with drilling expected to start third quarter in 2017. The Tender Support Vessel (TSV) project at Oseberg Øst is expected to commence drilling support operations in 2016.

Gullfaks has been developed with three large concrete production platforms. Since production started on Gullfaks in 1986, five satellite fields have been developed with subsea wells that are remotely controlled from the Gullfaks A and C platforms.

Drilling of the new Gullfaks South Increased Oil Recovery (GSO IOR) project wells is ongoing. Operations on the satellites will continue with a mobile rig until September 2016 and plan for development and operation for Shetland/Lista was delivered in second quarter of 2015.

The Gullfaks Rimfaksdalen (PDO) was submitted in 2014 and production will start up in the fourth quarter of 2016. Drilling of wells was completed in 2015. The projects Gullfaks B Drilling Upgrade and Gullfaks South IOR both started up in 2015.

Kvitebjørn is a gas and condensate field. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket.

The **Valemon** field is a gas and condensate field between Kvitebjørn and Gullfaks South. Valemon is built as a normally not manned, fixed steel platform with separation facilities for gas, condensate and water. The condensate is piped to Kvitebjørn for stabilisation and from there to the Mongstad refinery near Bergen. The production started in January 2015.

Visund is an oil and gas field development that includes floating drilling, production and living quarter units and two subsea templates, in the northern and southern parts of the field.

Grane is Statoil's largest producing heavy oil field. The Svalin field is a tie-in to Grane platform.

The Heimdal platforms are a hub for the processing and distribution of gas to the European gas markets. The hub consists of an integrated steel platform and a riser platform. During 2015 Heimdal has plugged and abandoned its production wells in the main reservoir. Heimdal will start production in 2016 from one new well drilled from the modular rig which was temporarily installed for plugging and abandonment activity.

3.5.2.4 Operations South

The main producing fields in Operations South are Sleipner, Gudrun, Statfjord and Snorre.

Operation South represents a mature oil and gas province. However, it still remains a significant contributor to Statoil's equity production and new fields are under development in the area. Main focus in the area is to capitalise on existing fields through profitable realisation of increased oil potential and successful implementation of new developments.

Sleipner consists of the Sleipner East, Gungne and Sleipner West gas and condensate fields. The gas from Sleipner has a high level of CO. This is extracted at the field and re-injected into a sand layer beneath the seabed to reduce carbon dioxide emissions to the air. Sleipner also processes gas, condensate and oil from Gudrun, Volve and Sigyn. The Gina Krog field, currently under development, will also be tied back to Sleipner.

The **Gudrun** field is a separate steel jacket-based process platform for separation of oil and gas, with separate pipelines transporting gas and partly stabilised oil from Gudrun to Sleipner.

Statfjord has been developed using three fully integrated platforms supported by gravity-based structures with concrete storage cells and an offshore loading system. Statfjord North, Statfjord Øst and Sygna are satellite fields have all been developed using subsea templates tied back to Statfjord C.

The **Snorre** field has two floating platforms and one subsea production system connected to the Snorre A platform. In addition, the satellite fields Tordis and Vigdis are part of Snorre business unit and are tied back to Gullfaks C and Snorre A, respectively.

3.5.2.5 Partner-operated fields

Partner-operated fields account for approximately 11% of our total oil and gas production on the NCS. The main producing fields are Ormen Lange, Skarv and Ekofisk.

Statoil's partner operated fields NCS portfolio is organised under Operations South.

Ormen Lange operated by Shell, is a deepwater gas field in the Norwegian Sea. The well stream is transported to an onshore processing and export plant at Nyhamna.

Skarv is an oil and gas field located in the Norwegian Sea, with BP as operator. The field development includes a floating production, storage and offloading vessel (FPSO) and five subsea multi-well installations.

Ekofisk is operated by ConocoPhillips. It consists of the Ekofisk, Eldfisk and Embla fields, and Tor. The Eldfisk II project delivered a new PDQ platform early 2015 that will serve as Eldfisk field center.

Edvard Grieg is an oil field located in the Utsira High Area. The field development includes a fixed steel jacket with processing and export facilities. Edvard Grieg is operated by Lundin. Production started on 28 November 2015 according to plan. Two wells were ready at start-up. Drilling will continue and a total of 10 production wells and four injection wells are planned.

3.5.3 Exploration on the NCS

Continued high exploration activity on the NCS

An extensive drilling program in 2015 resulted in 21 completed wells, of which 10 were discoveries. A total of 16 wells were Statoil operated.

Statoil has delivered an application for the 23rd concession round on the NCS. The round covers 57 blocks and parts of blocks, with three in the Norwegian Sea and 54 in the Barents Sea. South-East Barents Sea is the first new exploration acreage area opened on the NCS since 1994. Statoil and 15 other companies cooperate in the Barents Sea Exploration Collaboration (BaSEC) project to find common solutions for exploration operations in the Barents Sea and to ensure cost-effectiveness and good safety standards.

Statoil has been awarded interest in 24 licences in the Awards in Predefined Areas (APA) round 2015 on the NCS, 13 of those as operator and 11 as partner. Statoil has been awarded new licences in all three NCS provinces - North Sea, Norwegian Sea and the Barents Sea.

In general, Statoil's exploration strategy on the NCS is reflected in its diverse exploration portfolio, which ranges from frontier drilling to infra-structure led exploration close to existing infrastructure.

The table below shows the exploration and development wells drilled on the NCS in the last three years.

	2015	2014	2013
North Sea			
Statoil operated exploratory	11	11	11
Partner operated exploratory	3	7	10
Norwegian Sea			
Statoil operated exploratory	5	0	7
Partner operated exploratory	1	1	1
Barents Sea			
Statoil operated exploratory	0	9	2
Partner operated exploratory	1	1	4
Totals			
Exploratory	21	29	35
Exploration extension wells	3	2	7

Potential producing areas

In addition to producing areas, Statoil operates a significant number of exploration licences. Exploration takes place in undeveloped frontier areas as well as near existing infrastructure and producing fields.

Area	Square km (NCS Total)	Square km (Statoil)	Change vs 2014	Number of licenses (NCS Total)	Number of licenses (Statoil equity)	Number of licenses (Statoil operated)	New licenses (Statoil equity)	New licenses (Statoil operated)
North Sea	43,928	13,884	(1,006)	304	125	95	9	7
Norwegian Sea	37,784	12,581	(1,681)	144	79	55	9	4
Barents Sea	32,998	13,802	(135)	63	31	19	1	-
NCS total	114,710	40,267	(2,822)	511	235	169	19	11

North Sea
In the North Sea, Statoil participated in 14 exploration wells. Statoil operated ten of the exploration wells with seven discoveries.

Norwegian Sea
In the Norwegian Sea, Statoil participated in six exploration wells. Statoil operated five of the exploration wells with three discoveries.

Barents Sea
No Statoil operated wells in 2015. One partner operated well was completed in 2015.

3.5.4 Fields under development on the NCS

The main sanctioned development projects on the NCS.

The table below shows some key figures as of 31 December 2015 for Statoil's major development projects on the NCS.

Sanctioned projects	Operator	Statoil's equity share	Time of sanctioning	Production start
Aasta Hansteen	Statoil	51.00%	2013	2018
Johan Sverdrup	Statoil	40.01%	2015	2019
Gina Krog	Statoil	58.70%	2012	2017
Ivar Aasen	Det Norske	41.47%	2012	2016
Goliat	Eni	35.00%	2009	2016
Martin Linge	Total	19.00%	2011	2016

Johan Sverdrup is an oil discovery in the southern part of the North Sea, approximately 140 km west of Stavanger. A plan for development and operation was submitted in February 2015 and approved by the Norwegian authorities in August 2015. The Phase 1 of the development will consist of 35 production and water injection wells and a field center with four platforms: A living quarter platform, a wellhead platform with permanent drilling facility, a processing platform and a riser and utility platform. The crude oil will be exported to Mongstad through a 274 km long dedicated pipeline, and the gas will be exported to the gas processing facility at Kårstø through a 156 km long pipeline via a subsea connection to the Statpipe pipeline. The expected production start-up is in the fourth quarter of 2019.

Aasta Hansteen is a deep water gas discovery in the Norwegian Sea. The development concept includes three subsea templates tied in to a floating processing unit with gas export through a new pipeline, Polarled, to Nyhamna and further exportation through the Langeled pipeline. The Aasta Hansteen processing unit can also serve as a hub for other potential discoveries in the area. Expected production start-up is in 2018.

Gina Krog is an oil and gas discovery in the North Sea approximately 30 kilometres north of the Sleipner field. The field development concept includes a steel-jacket platform. Oil will be exported via offshore loading from a floating storage unit. Due to the high condensate content, the rich gas will be exported via Sleipner, where it will be further processed. The development concept also includes gas injection in order to maximise the recovery factor for the field. The development concept includes a total of 15 wells. Expected production start-up is in 2017.

Ivar Aasen is an oil and gas field located in the Utsira High Area. The development includes a fixed steel jacket with partial processing and living quarters tied in as a satellite to Edvard Grieg for further processing and export. The Ivar Aasen development is operated by Det norske, The operator expects production start-up in the fourth quarter of 2016.

Goliat is the first oil field to be developed in the Barents Sea. The field is being developed by means of subsea wells tied back to a circular floating production, storage and offloading vessel (FPSO). The oil will be offloaded to shuttle tankers. The Goliat development is operated by Eni who expects production start-up during first quarter of 2016.

Martin Linge is an oil and gas field, operated by Total, near the British sector in the North Sea. The reservoir is complex with gas under high pressure and high temperatures. The development includes a platform as a fixed steel jacket with processing and export facilities. Electrical power will be supplied from Kollsnes. The operator expects production start-up in 2018.

Redevelopment on the NCS - Improved oil recovery (IOR)
In 2015 Statoil started the world's first subsea gas compression plant at the Åsgard field. Processing on the seabed, particularly gas compression, is important for developing seabed solutions for areas of deeper water and in colder and more challenging areas. Åsgard's subsea compression, the world's first subsea gas compression plant, is one of Statoil's most demanding technology projects. The compressors will increase recovery from the Midgard reservoir on Åsgard from 67 percent to 87 percent, and from the Mikkel reservoir from 59 percent to 84 percent, extending the operational life of the fields up to 2032 and contributing to significant reduction in energy consumption and CO_2 emissions over the fields' lifetimes.

The **Gullfaks subsea compression** project the second largest subsea gas compression project being developed by Statoil on the NCS. Subsea gas compression will have a significant impact on the Gullfaks field as this technology, combined with conventional low-pressure production, is expected to lift the recovery rate from the Gullfaks South Brent reservoir from 62% to 74%.

The **Smørbukk South Extension** project, in the Åsgard field, is a world class project production from tight formations previously regarded as infeasible. Production began in September 2015 through the combination of wells with long well sections and "fishbones", a new completion technology implemented for the first time on the NCS, and further utilisation of existing infrastructure at Åsgard.

Troll A field's two new topside compressors started operating in October 2015. Installation of these compressors is an important step to achieve the Troll field's long-term production profile, which now extends to 2063. They are operated with power from shore, which reduces the field's CO_2 emissions significantly.

The **Gullfaks South Oil (GSO)** project started production in July 2015 and will increase recovery from the Gullfaks area. It includes two subsea templates, four production wells, two gas injectors, a gas injection pipeline and umbilicals and power cables for pipeline heating. The project utilise spare processing capacity and will extend the Gullfaks A platform life beyond 2030.

The **Gullfaks B lifetime extension** project aims at extending the drilling program on the Gullfaks B platform until 2032. Operation started on August 2015. Many of the future wells in Gullfaks B are water injection wells that will help maintain production from all three of the platforms in the field through increased pressure support in the reservoir. The drilling upgrade also provides the opportunity to connect to smaller producers from the surrounding area.

The **Ormen Lange** onshore compression project being executed as part of the overall expansion of the Nyhamna facility to handle third-party gas entering the plant through the new Polarled pipeline. The two 37 MW onshore compressors are scheduled for start-up in July 2017.

These projects are all examples of Statoil's efforts to maximise recovery from existing fields. They have also opened opportunities for technology application to realise volumes from other fields with similar conditions.

3.5.5 Decommissioning on the NCS

Under the Petroleum Act, the Norwegian government has imposed strict procedures for removal and disposal of offshore oil and gas installations. The Convention for the Protection of the Marine Environment of the Northeast Atlantic (OSPAR) stipulates similar procedures.

Glitne ceased production in February 2013 and decommissioning of the field has been ongoing 2013 - 2015. Permanent plugging and abandonment of the seven wells completed in October 2014. All facilities/equipment were removed from the field in 2015. Safety zones in the area have been repealed and national maps updated.

Huldra ceased production in September 2014, after 13 years in production. Permanent plugging and abandonment of six wells is planned for 2016 and the plan is that the Huldra topside facilities will be removed in 2019.

Yttergryta is a subsea field with one production well that ceased production in 2013. Permanent plugging of the well was completed early in 2015.

On **Heimdal** a modular drilling rig has been successfully installed in order to plug and abandon all 12 wells at the Heimdal main reservoir. The plug and abandonment project started in the fourth quarter 2014, and is scheduled to be finalised by second quarter 2016.

During 2015 there were permanent plugging and abandonment operations at Statfjord Øst, Statfjord A, Sleipner and Tordis. In addition Åsgard decommissioned part of the Midgard flowline loop in 2015.

For further information about decommissioning see note 2 *Significant accounting policies* to the Consolidated financial statements.

3.6 Development and Production International (DPI)

3.6.1 DPI overview

Statoil is present in several of the most important oil and gas provinces in the world.

Development and Production International (DPI) is responsible for all development and production of oil and gas outside the Norwegian continental shelf (NCS).

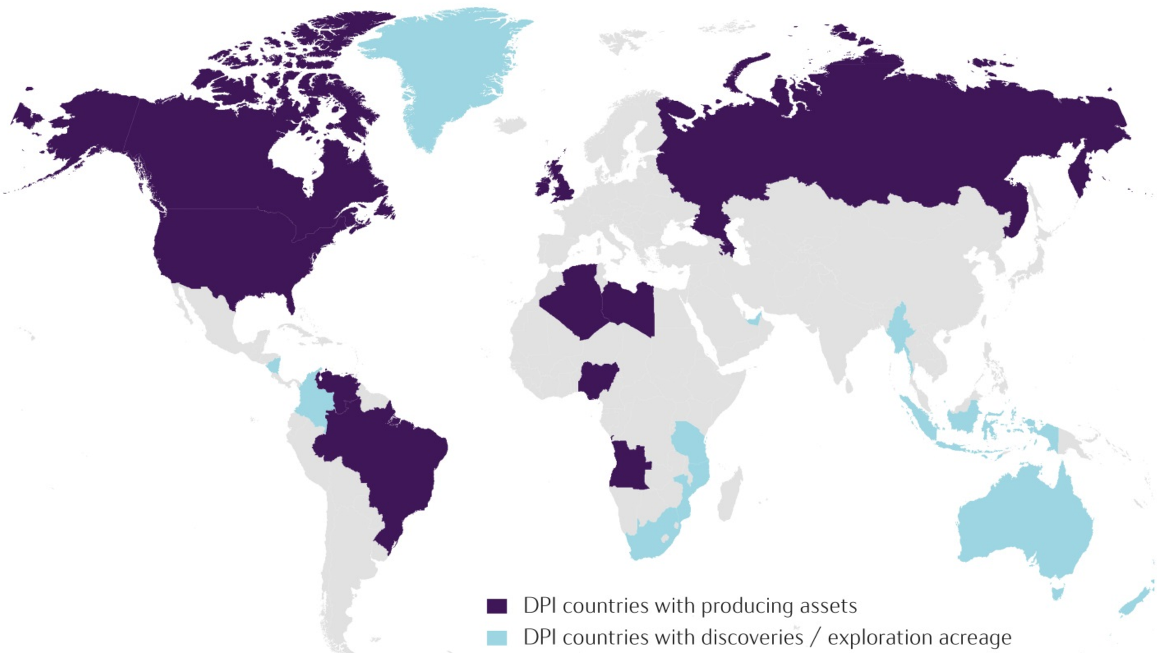
In 2015, DPI was engaged in production in 11 countries: Algeria, Angola, Azerbaijan, Brazil, Canada, Ireland, Nigeria, Russia, the UK, the US, and Venezuela. DPI produced 37% of Statoil's total equity production of oil and gas in 2015.

As of 31 December 2015, Statoil has exploration licenses in North America (Canada and US), South America and sub-Saharan Africa (Angola, Brazil, Colombia, Mozambique, Nicaragua, Suriname, South Africa and Tanzania), North Africa (Algeria and Libya), Europe and Asia (Azerbaijan, Greenland, Indonesia, Myanmar, Russia and the UK) as well as Oceania (Australia and New Zealand). The main development projects in which DPI is involved are in Brazil, Canada, the UK, and the US.

Statoil also has representative offices in Kazakhstan, Mexico and United Arab Emirates.

Statoil closed its office in Iran in 2013 but has residual payment obligations for tax and social security under legacy contracts in Iran. These will be dealt with in accordance with all applicable sanctions. See section 5.1.1 *Risks related to our business* for information regarding sanctions towards Iran.

The map shows Statoil's international producing countries and additional countries where Statoil has discoveries and/or exploration acreage.



Key events and portfolio developments in 2015:

- Eight wells (exploration and appraisal) were announced as discoveries in 2015, including the Piri 2, Tangawizi 2 and Mdalasini (Statoil-operated) discoveries in Tanzania
- Statoil accessed new acreage in Lampyrus in Russia, Mozambique, Nicaragua, Flemish Pass basin and Nova Scotia in East Coast Canada and South Africa
- In January, a transaction with Southwestern Energy was closed. The agreement reduced Statoil's working interest in the non-operated US southern **Marcellus** onshore asset from 29% to 23%
- Delay of **Big Foot** development first oil in the US Gulf of Mexico. The operator Chevron expects first oil in 2018. Initial plans called for production to start in late 2015, however, installation was halted and the tension leg plarform (TLP) moved to sheltered waters following damage to subsea installation tendons in late May 2015
- In April, the **Kizomba Satellites Phase 2** project in Block 15 offshore Angola started production
- In April, Statoil completed its sale of its remaining 15.5% interest in **Shah Deniz** and the **South Caucasus Pipeline (SCP)** to the Malaysian oil and gas company PETRONAS. The effective date was 1 January 2014
- In August, the **Peregrino** field offshore Brazil passed a significant milestone with 100 million barrels of oil produced since production started in April 2011
- On 30 December, the Shell operated **Corrib** gas field in Ireland started production
- In December, Statoil completed the sale of its 20% interest in **Trans Adriatic Pipeline AG (TAP)** to the Italian gas infrastructure company Snam. TAP is an 882 km-long section of the Southern Gas Corridor, linking Shah Deniz Stage 2 to gas markets in Europe
- In December, transactions with Repsol were announced. As a result of these transactions, Statoil's working interest in the US **Eagle Ford** increased from 50% to 63% and Statoil took full operatorship. In addition, Statoil will assume operatorship of the **BM-C-33** licence in Brazil's Campos basin and acquire a 31% equity share in the UK licence for **Alfa Sentral**, a field which spans the UK-Norway maritime border. The transactions for BM-C-33 and Alfa Sentral are pending approval from relevant government authorities
- In February 2016, the In Salah Gas joint venture announced the start- up of operations at the **In Salah Southern Fields** project in Algeria
- Significant impairment losses on assets and oil and gas prospects and signature bonuses were recognised in 2015, see section 4.1.5 *DPI profit and loss analysis* for further details

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by high costs and declining returns is addressed in the section 2 *Strategy and market overview*.

3.6.2 International production

Statoil's entitlement production outside Norway was about 32% of Statoil's total entitlement production in 2015.

The following table shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2015, 2014 and 2013. Entitlement production figures are after deductions for production sharing and profit sharing. For US assets entitlement production are expressed net of royalty interests. For all other countries royalties paid in-cash are included in entitlement production and royalties payable in-kind are excluded.

	For the year ended 31 December		
Entitlement production	**2015**	**2014**	**2013**
Oil and NGL (mboe per day)	436	383	354
Natural gas (mmcm per day)	23	26	23
Total (mboe per day)	580	546	502

The table below provides information about the fields that contributed to production in 2015

Producing fields during calendar year 2015

Field	Statoil's equity interest in %	Operator	On stream	Licence expiry date	Average daily equity production mboe/day	Average daily entitlement production mboe/day
North America					282.3	239.7
US: Marcellus [1]	Varies	Statoil/others	2008	HBP[2]	115.7	96.9
US: Bakken [1]	Varies	Statoil/others	2011	HBP[2]	61.6	49.3
US: Eagle Ford [1]	Varies	Statoil	2010	HBP[2]	34.7	26.6
US: Tahiti	25.00	Chevron	2009	HBP[2]	16.9	13.9
US: Caesar Tonga	23.55	Anadarko	2012	HBP[2]	9.1	8.7
US: St. Malo	21.50	Chevron	2014	HBP[2]	7.6	7.6
US: Jack	25.00	Chevron	2014	HBP[2]	6.6	6.6
Canada: Leismer Demo	100.00	Statoil	2010	HBP[2]	19.9	19.9
Canada: Terra Nova	15.00	Suncor	2002	2022	5.4	5.4
Canada: Hibernia/Hibernia southern extension[3]	Varies	HMDC	1997	2027	4.8	4.8
South America					43.5	43.5
Brazil: Peregrino	60.00	Statoil	2011	2034	43.5	43.5
Sub-Saharan Africa					273.3	197.8
Angola, Block 17	23.33	Total	2001	2022-34[4]	161.9	113.9
Angola, Block 15	13.33	ExxonMobil	2004	2026-32[4]	41.8	22.6
Angola, Block 31	13.33	BP	2012	2031	20.9	19.0
Angola: Block 4/05[5]	20.00	Sonangol P&P	2009	2026	1.4	1.3
Nigeria: Agbami	20.21	Chevron	2008	2024	47.3	41.0
North Africa					49.6	43.6
Algeria: In Salah	31.85	Sonatrach/BP/Statoil	2004	2027	32.5	30.6
Algeria: In Amenas	45.90	Sonatrach/BP/Statoil	2006	2022	17.1	13.3
Libya: Mabruk	12.50	Mabruk Oil Operations	1995	2033	0.0	(0.0)[6]
Libya: Murzuq	10.00	Akakus Oil Operations	2003	2033	0.0	(0.2)[6]
Europe and Asia					78.3	43.9
Azerbaijan: ACG	8.56	BP	1997	2024	54.3	24.2
Azerbaijan: Shah Deniz [7]	15.50	BP	2006	2041	12.0	10.0
Russia: Kharyaga	30.00	Total	1999	2032	9.4	7.1
UK: Alba	17.00	Chevron	1994	2018	2.5	2.5
UK: Jupiter	30.00	ConocoPhillips	1995	HBP[2]	0.1	0.1
Ireland: Corrib[8]	36.50	Shell	2015	2031	0.0	0.0
Total Development and Production International (DPI)					727.0	568.5
Equity accounted production						
Venezuela: Petrocedeño[9]	9.68	Petrocedeño	2008	2033	11.6	11.6
Total Development and Production International (DPI) including share of equity accounted					738.7	580.2

1) Statoil's actual working interest can vary depending on wells and area
2) Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, besides continue being in production status, other regulatory requirements must be met
3) Statoil's working interests are 5.0% in Hibernia and 9.0% in Hibernia southern extension
4) Varies by field
5) Statoil relinguished Block 4/05 in September 2015
6) Zero production in 2015, adjustment of 2014 volume
7) Statoil divested the asset on 30 April 2015
8) New gas field which started production on 30 December 2015
9) Petrocedeño is a non-consolidated company and accounted for pursuant to the equity accounting method

The table below provides information about production per country in 2015.

Country	Average daily equity production mboe/day[1]	Average daily entitlement production mboe/day
North America	282.3	239.7
US	252.2	209.6
Canada	30.1	30.1
South America	43.5	43.5
Brazil	43.5	43.5
Sub-Saharan Africa	273.3	197.8
Angola	226.0	156.8
Nigeria	47.3	41.0
North Africa	49.6	43.6
Algeria	49.6	43.9
Libya	0.0	-0.3
Europe and Asia	78.3	43.9
Azerbaijan	66.3	34.2
Russia	9.4	7.1
UK	2.6	2.6
Total Development and Production International (DPI)	727.0	568.5
Equity accounted production		
Venezuela: Petrocedeño[2]	11.6	11.6
Total Development and Production International (DPI) including share of equity accounted production	738.7	580.2

1) In PSA countries our share of capital expenditures and operational expenses are computed on the basis of equity production.

2) Petrocedeño is accounted for pursuant to the equity accounting method.

The following sections provide information about the main producing assets internationally. See section 4.1.5 *DPI profit and loss analysis* for a discussion of the results of operations for year end 2015.

3.6.2.1 North America

Production in North America comprises the US and Canada.

US

Statoil is positioned in the fast-growing US onshore oil and gas industry. Statoil has had strong growth in production within US shale since entering the first play in 2008.

Statoil entered the **Marcellus** shale gas play, located in the Appalachian region in north east US, in 2008 through a partnership with Chesapeake Energy Corporation, acquiring 32.5% of Chesapeake's 1.8 million acres in Marcellus. Statoil has continued to acquire acreage within the play, with a net acreage position of 410,000 acres. The most recent divestments occurred in 2014 with Southwestern. The divested share represents approximately 30,000 acres. Southwestern took over operatorship in this US southern Marcellus area through a transaction with Chesapeake in December 2014.

Statoil entered the **Bakken** tight oil play through the acquisition of Brigham Exploration Company in December 2011. Statoil's net acreage position in Bakken and Three Forks shale formation at the end of 2015 was 249,000 acres.

Statoil entered the **Eagle Ford** shale formation located in southwest Texas in 2010. Through agreements with Enduring Resources LLC and Talisman Energy Inc., Statoil acquired 67,000 net acres. In 2013, Statoil became operator for 50% of the Eagle Ford acreage in 2010 and gradually took over full operatorship of the Statoil operated acreage in 2013. As part of a global transaction in December 2015 with Repsol, which acquired Talisman in May 2015, Statoil increased its working interest and took full operatorship of all of the assets in the Eagle Ford Shale. As a consequence, Statoil has a total working interest of 63% representing an addition of 15,000 net acres for a total of 72,000 leaseholds. Our joint venture partner, Repsol, continues to hold 37% working interest.

Statoil is positioned in the Gulf of Mexico for the following offshore developments:

The **Tahiti** oil field is located in the Green Canyon area. The development includes a floating spar facility. As of 31 December 2015, there were nine production and three water injection wells in operation, and additional wells will be phased in over time to fully develop the field.

The **Caesar Tonga** oil field is located in the Green Canyon area. As of 31 December 2015, there were six producing wells tied back to the Anadarko-operated Constitution spar host, and additional production wells will be phased in over time.

The **Jack** and **St. Malo** oil fields are located in the Walker Ridge area. The fields are subsea tie-backs to the Chevron operated Walker Ridge Regional Host facility. First production was achieved in December 2014. As of 31 December 2015, there were three wells producing on Jack and three wells producing for St. Malo. Additional production wells will be phased in over time.

Canada

Statoil entered the Alberta oil sands in 2007 through a corporate acquisition of North American Oil Sands Corporation. In May, 2014, Statoil and PTTEP completed a transaction to divide their respective interests in the Kai Kos Dehseh (KKD) oil sands project with an effective date of 1 January 2013.

Following the transaction with PTTEP, Statoil continues as operator and 100% working interest owner for the Leismer and Corner projects which together comprise 123,200 net acres of oil sands leases in Alberta. **The Leismer Demonstration Plant** (LDP) is the first phase of the KKD development and has been in operation since 2010. The in-situ technology known as SAGD (steam assisted gravity drainage), injects steam into the oil bearing formation to recover bitumen which is then pumped to the surface. Further oil sands development could involve expanding production capacity of the Leismer facility and/or the greenfield development of the Corner project. At this time, there are no near term plans to further develop either project.

In addition, we have interests in the Jeanne d'Arc Basin offshore the province of Newfoundland and Labrador in the partner operated producing oil fields **Terra Nova, Hibernia** and **Hibernia Southern Extension**. On 1 December 2015, Statoil's interest in Hibernia Southern Extension was reduced from 10.5% to 9.0% due to a redetermination process.

3.6.2.2 South America

Statoil's production activities in South America comprise the Peregrino operatorship in Brazil and the Petrocedeño project in Venezuela.

Brazil

The **Peregrino** field is a heavy oil field located in the Campos Basin, about 85 kilometres off the coast of Rio de Janeiro. The field came on stream in 2011.The oil is produced from two wellhead platforms with drilling capability and it is processed on the Peregrino FPSO. Statoil holds a 60% ownership interest in the field and is operator. In August 2015, the Peregrino field passed a significant milestone with 100 million barrels of oil produced since production start.

Venezuela

Petrocedeño produces extra-heavy crude oil from the Junin area in the Orinoco Belt. The oil is transported through pipeline to a plant at the Jose Industrial Complex at the coast nearby Puerta La Cruz where it is upgraded into a light crude and exported.
For information related to Venezuela's financial risk see section 5.2.2 *Managing financial risk*.

3.6.2.3 Sub-Saharan Africa

Statoil's production activities in Sub-Saharan Africa comprise Angola and Nigeria.

Angola

The deep water blocks 17, 15, 31 and 4/05 contributed with 40% of Statoil's equity liquid production outside Norway in 2015. Each block is governed by a production sharing agreement (PSA) which sets out the rights and obligations of the Parties, including mechanisms for sharing of the production with the Angolan state oil company Sonangol.

Block 17 comprises production from four FPSOs; **CLOV**, **Dalia**, **Girassol** and **Pazflor**.

Block 15 has production from four FPSOs: **Kizomba A**, **Kizomba B**, **Kizomba C-Mondo**, and **Kizomba C-Saxi Batuque**. In April 2015, the **Kizomba Satellites phase 2 project**, which consists of the fields Bavuka, Kakocha, and Mondo South started production. The fields are developed with subsea wells and infrastructure tied back to the Kizomba B and Mondo FPSO vessels.

Block 31 has production from the **PSVM** FPSO.

Statoil had production from the **Gimboa** FPSO on **Block 4/05** until the company exited the Block in September 2015.

The FPSOs serve as production hubs and receive oil from a large number of wells and more than one field each. In 2015, new wells were added and set into production on Block 15, Block 17 and Block 31.

Nigeria
In Nigeria, Statoil has a 20.2% interest in the Agbami deep water field which is located 110 km off the coast of the Central Niger Delta region. The field is developed with subsea wells connected to an FPSO. The **Agbami** field straddles the two licenses OML 127 and OML 128 and is operated by Chevron under a Unit Agreement. Statoil has 53.85% interest in OML 128.

For information related to the Agbami redetermination process and the dispute between the Nigerian National Petroleum Corporation and the partners in Oil Mining Lease (OML) 128 concerning certain terms of the OML 128 Production Sharing Contract, see section 5.3 *Legal proceedings* and note 23 *Other commitments and contingencies*.

3.6.2.4 North Africa

Statoil had in 2015 production in North Africa from Algeria.

Algeria
The **In Salah** onshore gas development, in which Statoil has a working interest of 31.85%, is Algeria's third-largest gas development. A PSA including mechanisms for revenue sharing, governs the rights and obligations of the Parties and establishes a joint operatorship between Sonatrach, BP and Statoil.

In February 2016, the In Salah Gas joint venture announced the introduction of gas in the **In Salah Southern Fields** processing facilities. Gas export from the project started in March. This project, which is led by Statoil on behalf of the Joint Venture, will mature the remaining four discoveries into production. The southern fields (Gour Mahmoud, In Salah, Garet el Befinat and Hassi Moumene) will tie in to existing facilities in the northern fields.

The **In Amenas** onshore development is the fourth-largest gas development in Algeria. It also contains significant liquid volumes. The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil, where Statoil's share of financing the investments (working interest) is 45.9%. A PSA, including mechanisms for revenue sharing, governs the rights and obligations of the Parties and establishes a joint operatorship between Sonatrach, BP and Statoil.

The In Amenas plant has since April 2013 produced from two out of three trains. The production has been relatively stable. The third train, which also was damaged in the January 2013 terrorist attack, is expected to restart in the second quarter of 2016.

Libya
There has not been any oil production from the **Mabruk** or the **Murzuq** assets in 2015 due to the security situation in the country.

3.6.2.5 Europe and Asia

Statoil's production in Europe and Asia encompasses Azerbaijan, Russia, the United Kingdom and Ireland.

Azerbaijan
The **Azeri-Chirag-Gunashli (ACG)** oil field in the Caspian Sea has production from 6 fixed platforms. The oil is transported through pipelines to the Sangachal onshore terminal near Baku. From the terminal the oil is exported to the world markets.

Statoil has an 8.7% stake in the 1,760 km Baku-Tbilisi-Ceyhan (BTC) oil pipeline that is used to transport ACG oil to the southern Turkish port of Ceyhan.

In April 2015, Statoil completed the sale of its remaining 15.5% interest in **Shah Deniz** and the **South Caucasus Pipeline (SCP)** to the Malaysian oil and gas company PETRONAS. See note 4 *Acquisitions and dispositions* of the Consolidated financial statements for further details.

Russia
The **Kharyaga** oil field is located onshore in the Timan Pechora basin in north-west Russia. The field is governed by a PSA.
For information related to risk in Russia see section 5.1.1 *Risks related to our business*.

United Kingdom
The **Alba** oil field is located in the central part of the UK North Sea. **Jupiter** is a gas field located in the southern part of the UK North Sea. The decommissioning of the Jupiter wells is planned to start in 2016.

Ireland
On 30 December 2015 production started on **Corrib** gas field off Ireland's northwest coast. Corrib consists of a subsea development with a pipeline to an onshore processing terminal from which gas will be transported to the Irish market. The onshore processing terminal is located approximately 9 km inland.

3.6.3 International exploration

Statoil continued with high international exploration activity in 2015.

In 2015 Statoil carried out significant international exploration activity, as is shown by the company's involvement in 18 completed wells (including both Statoil-operated and partner-operated activities). Eight wells (exploration and appraisal) were announced as discoveries in the period, including the Piri 2, Tangawizi 2 and Mdalasini (Statoil-operated) discoveries in Tanzania.

The table below shows the exploratory wells drilled internationally in the last three years.

		2015	2014	2013
North America	- Statoil operated	8	3	7
	- Partner operated	0	0	4
South America/sub-Saharan Africa	- Statoil operated	3	8	6
	- Partner operated	5	9	4
North Africa	- Statoil operated	0	0	0
	- Partner operated	0	0	1
Europe and Asia	- Statoil operated	2	2	0
	- Partner operated	0	1	2
	Totals	18	23	24

The regions where Statoil had exploration activity in 2015 are presented below.

North America

US

Statoil operated five wells in the Gulf of Mexico (Yeti-1, Yeti Side track, Yeti Appraisal, Thorvald-1 and Power Nap). Yeti-1 and its side track were discoveries, Yeti appraisal confirmed the volumes discovered. Power Nap is ongoing at year end.

Statoil has cancelled the contract for the Discoverer Americas rig in December 2015. Statoil was in the current environment unable to secure additional activity for the rig for the remainder of the contract period, ending in May 2016.

Canada

The West Hercules rig arrived in Canada in November 2014, for a 550 days drilling campaign, which continues into early-2016. The programme has focused on appraisal and near field exploration wells in the greater Bay du Nord discovery area, as well as select exploration prospects in the greater Flemish Pass Basin.

Statoil and its partners were the successful bidders for six exploration licences in the Flemish Pass Basin, offshore Newfoundland, and two licences offshore Nova Scotia in East Coast Canada in 2015. Statoil will operate seven of the eight leases awarded.

South America and sub-Saharan Africa

Angola Kwanza

Statoil acquired a solid acreage position in the pre-salt play of the Kwanza Basin in 2011 with the operatorship in Block 38 and 39 and a partner position in Blocks 22, 25 and 40. The work program included eight commitment wells, two Statoil operated and six partner operated. So far six wells have been completed. In 2015 two partner operated wells were drilled, Umbundu in block 40, Catchimanha in Block 22. For more information see note 12 *Intangible assets*.

Brazil

All exploratory well operations during 2015 were conducted on BM-C-33 license as part of Pão de Açucar and Seat appraisal activities. The Pão de Açucar discovery was fully evaluated by drilling two wells (PdA-A1 and PdA-A2) and performing a successful DST (Drill Stem Test) on PdA-A2. The Seat-2 well was re-entered to perform a DST. In agreement with its licence partners, Statoil will assume operatorship of the BM-C-33 licence subject to receiving government approval.

Colombia

Statoil has accessed three licences in 2014, representing access at scale in relatively frontier acreage. In the COL-4 licence, an environmental and social impact study has been completed.

Statoil farmed-in to a 10% equity share in the Tayrona licence and a 20% share in the Gua Off licence in 2014. The Orca-1 well in the Tayrona licence was announced as a gas discovery in 2014.

Mozambique
The 5th licence round was announced during the third quarter of 2015. Statoil together with partners submitted a winning bid in the A5-A block located in the Angoche area. Eni is the operator of the joint venture with 34% participating interest. Statoil's equity is 25.5%. Final award is expected mid-2016 subject to successful negotiations.

Tanzania
The Tanzania drilling campaign using the Discoverer Americas rig was completed in 2015 after having drilled the Mdalasini prospect and the Tangawizi-2 appraisal well. The discoveries of natural gas in Mdalasini-1, Piri-1 and Giligiliani-1 have significantly increased the total in-place volumes in Block 2.

South Africa
Statoil completed a farm-in transaction in October 2015 with ExxonMobil acquiring a 35% interest in the ER 12/3/154 Tugela South Exploration Right. The Operator is Exxon with 40% equity. The farm-in represents a country entry for Statoil into South Africa. Statoil intends to participate at an early phase of exploration with a step-wise exploration programme.

Nicaragua
In 2015, Statoil together with partner Empresa Nicaraguense del Petroleo (Petronic) has been awarded four licences offshore the Nicaraguan Pacific. Statoil is the operator with 85% equity with the Petronic holding the remaining equity. 2D seismic data has been acquired and processed during 2015 and subsurface studies are underway.

North Africa

Algeria
Statoil and Shell were awarded the Timissit licence in the Berkin basin onshore Algeria in September 2014. Statoil is the operator with 30% equity.

The award represents an opportunity to test a potentially large unconventional (shale) resource play.

The work commitment (up to the first exit point in 2018) is 3D seismic and two vertical wells.

Europe (excluding Norway), Asia and Australia

UK
In 2014 Statoil was awarded interests in 12 exploration licences in the UK 28th licensing round, nine as operator. Significant positions have been taken both in mature parts of the Central North Sea, such as in the vicinity of the Mariner and Bressay projects, and in plays largely untested in UK waters. 11 of the licences are in the North Sea and one is west of the Hebrides. In 2015 two exploration wells were drilled. The Boatswain well in licence P1758 west of the Mariner field was a discovery. The Wall well in licence P2067 was dry. Work now continues to mature the broader UK exploration portfolio.

Greenland
Statoil, along with partners ConocoPhillips and Nunaoil, was awarded block 6 in the East Greenland licence round in December 2013. Statoil is the operator of the block. The licence has a 16-year exploration period.

Russia
Statoil is engaged in a strategic cooperation with Rosneft Oil Company (Rosneft) including a joint cooperation project aimed at undertaking seismic surveys and geological exploration, appraisal, development and production of potential hydrocarbons in four licences on the Russian continental shelf - the Magadan 1, Lisyansky and Kashevarovsky licences in the Sea of Okhotsk (south of the Arctic Circle), and the Perseevsky licence in the Barents Sea (north of the Arctic Circle). Two exploration wells are to be drilled in the Magadan 1 and Lisyansky licences in 2016. Additionally there are two joint cooperation projects onshore; pilot drilling and testing of the onshore heavy oil reservoir layer PK1 in the North Komsomolsky discovery, and the Domanik Sediments Difficult-to-Extract Hydrocarbons Project, aimed at pilot drilling and testing of the limestone Domanik formation in the Russian Volga-Urals basin. For each of these projects, Rosneft holds the majority interest, while Statoil holds a minority interest.

See section 5.1.1 *Risks related to our business* for information regarding sanctions against Russia.

Azerbaijan
The Joint Study Agreement (JSA) with SOCAR for the North Absheron area was completed in 2014. Exploration screening and prospect evaluation is being carried out on an ongoing basis for Azerbaijan offshore areas in order to identify new access opportunities.

Indonesia
Statoil signed the new offshore Aru Trough I PSC licence agreement in May 2015. The licence is adjacent to Statoil's existing exploration acreage in the Aru and West Papua IV licences. This is a low-cost access route into a frontier area with potential where Statoil is already present. This position strengthens the optionality in Statoil's long-term portfolio and secures potential upsides from existing exploration acreage.

Myanmar
Statoil and ConocoPhillips were awarded one exploration block (AD-10) in the Myanmar waters of the Bay of Bengal in 2014. A production sharing contract was signed in May 2015. Statoil (as operator) has completed the IEE (Initial Environmental Examination) and has set up a country office in Yangon.

Australia
In the Ceduna sub-basin in the Great Australian Bight, Statoil holds 30% interest in four exploration licences with BP as operator.

In October 2014, Statoil obtained 100% equity share in an exploration licence in the Exmouth Plateau in North Carnarvon basin.

New Zealand
Statoil is operator with 100% equity share in petroleum exploration permits 55781 and 57057 in the Reinga Basin offshore Northland's west coast. The licences were awarded in the New Zealand Block Offer 2013 and 2014 respectively.

The work programme is designed to fully evaluate the prospectivity of the licences in a step-wise manner within the 15-year licence time frame. Statoil completed 2D seismic data early 2015. Following an analysis and interpretation of this data, Statoil will decide whether to enter into the second exploration phase by mid-2017.

In the New Zealand Block Offer 2014 Statoil was also awarded 50% working interest in blocks 57083, 57085 and 57087 with Chevron as operator. The licences are located in the East Coast and Pegasus basins, southeast off New Zealand's North Island. The partnership is committed to acquire 2D seismic and 3D seismic within the first exploration period.

Faroe Islands
Following disappointing exploration activities, Statoil have relinquished all licences. The Statoil office in Torshavn closed down in 2015.

3.6.4 Fields under development internationally

The sanctioned development projects in which DPI is involved are in Algeria, Brazil, Canada, the UK, and the US.

This section covers selected projects under development and significant pre-sanctioned projects.

Sanctioned projects	Operator	Statoil's equity share	Time of sanctioning	Production start
US: Julia	Exxon Mobil	50.00%	2013	2016
US: Heidelberg	Anadarko	12.00%	2013	2016
US: Stampede	Hess	25.00%	2014	2018
US: Big foot	Chevron	27.50%	2010	2018
Canada: Hebron	Exxon Mobil	9.01%	2012	2017
Algeria: In Amenas Compression project	Sonatrach/BP/Statoil	45.90%	2010	2016
UK, Mariner	Statoil	65.11%	2012	2018
Brazil, Peregrino Phase II[1)]	Statoil	60.00%	2015	2019/20

1) Statoil made the investment decision on Peregrino Phase II project in December 2014 and submitted the Plan of Development to Brazilian authorities in January 2015.

3.6.4.1 North America

Statoil has a number of significant ongoing development projects in North America.

US Gulf of Mexico
The **Julia** oil field is located in the Walker Ridge area of the Gulf of Mexico near Jack and St Malo, and will be developed with subsea wells tied back to the shared JSM host facility. First oil is expected within mid-2016.

The **Heidelberg** oil field is located in the Green Canyon area. The development includes a Spar facility and first oil is expected within early-2016.

The **Stampede** oil field is located in the Green Canyon area. The development includes a tension-leg platform (TLP) with downhole gas lift and water injection from start of production. First oil is expected in 2018.

The **Big foot** oil field is located in Walker Ridge area. The development includes a dry tree TLP with a drilling rig. The operator Chevron expects first oil from Big Foot in 2018. Initial plans called for production to start in late 2015, however, installation was halted and the TLP moved to sheltered waters following damage to subsea installation tendons in late May 2015

US Onshore
US Onshore operations use hydraulic fracturing to liberate resources. Despite reduction in investment and activity level in recent years in shale plays **Bakken**, **Eagle Ford** and **Marcellus**, production growth continues. The increase in onshore production despite investment reduction is attributed to higher recovery per well due to enhanced completion and improved operational efficiency. See section 3.6.2.1 *North America* for further information.

Canada
The **Hebron** field is located in the Jeanne d'Arc basin offshore Newfoundland near the partner-operated producing fields Terra Nova, Hibernia and Hibernia Southern Extension. The Hebron field will be developed using a fixed gravity base structure (GBS) and first oil is expected in 2017. Effective January 1, 2016, Statoil's interest in Hebron was reduced from 9.7% to 9.0% due to a redetermination process.

Statoil has made oil discoveries in the Flemish Pass offshore Newfoundland comprising the **Bay du Nord** project, and work is on-going to assess options for developing this project. Statoil is the operator of Bay du Nord and holds a 65% working interest.

3.6.4.2 South America

In January 2015 Statoil submitted the Plan of Development (PoD) for Peregrino Phase II project in Brazil.

In December 2014, Statoil approved the investment decision for the development of the second phase of the Peregrino oil field. In January 2015 the PoD was submitted to the Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP) for approval. **Peregrino Phase II** project includes the Peregrino South and South West discoveries. The development consists of one wellhead platform tied back to the existing FPSO.

3.6.4.3 Sub-Saharan Africa

In Sub-Saharan Africa, Statoil is participating in the planning and development of Block 2 in Tanzania.

Tanzania
Statoil has made several large gas discoveries in Block 2 offshore Tanzania. Statoil is the operator of Block 2 and holds a 65% working interest. Work is on-going to assess options for developing the discoveries, including the construction of an onshore LNG plant jointly with the co-venturers in Blocks 1, 3 and 4 operated by BG.

3.6.4.4 North Africa

In 2015, Statoil's field developments in the North Africa were in Algeria.

The **In Amenas Gas Compression** project in Algeria, which is led by BP, was sanctioned in late 2010. The compressors are expected to come on stream in the fourth quarter of 2016. This will make it possible to reduce wellhead pressure and maintain plateau production. The In Amenas facilities are operated through a joint operatorship between Sonatrach, BP and Statoil.

In February 2016, the In Salah Gas joint venture announced the start- up of operations at the **In Salah Southern Fields** project in Algeria. For more information see section 3.6.2.4 *North Africa*.

3.6.4.5 Europe and Asia

In Europe and Asia, Statoil is participating in the planning and development of projects in the UK

United Kingdom
Statoil is the operator for the **Mariner** heavy oil project. In December 2012, Statoil made the investment decision to develop the Mariner oil field. The field development plan was approved by the UK authorities in February 2013. The concept selected includes a production, drilling and quarters platform based on a steel jacket, with a floating storage unit. Statoil expects production start in 2018.

The field development plan for Mariner includes a possibility of a future subsea tie-in of Mariner East, a small heavy oil discovery. Statoil is the operator of Mariner East.

Following completion of the farm down of 20.89% of P.726 (Mariner East) and 28.89% of P.979 (Mariner South) by Statoil to JX Nippon in third quarter 2015, Statoil holds a 65.11% interest in all Mariner licences.

Statoil is the operator for, and holds an 81.6% interest in **Bressay**. Bressay is also a heavy oil discovery. In February 2016, Statoil decided to pause the concept selection work on Bressay.

In November 2015, Statoil completed the purchase of First Oil's 24% equity share in the UK continental shelf (UKCS) licence P312. This UK licence and licence PL046 on the NCS comprise the **Alfa Sentral**, a gas and condensate field planned to be developed as a tie-back to the existing Sleipner infrastructure on the NCS. A pre unit agreement is in place between the UKCS and NCS Alfa Sentral Licenses, with an unitisation agreement to be negotiated prior to the investment decision.

In February 2016, Statoil signed an agreement with Talisman Sinopec North Sea Limited to acquire their 31% interest in the UK Alfa Sentral Licence P312. The transaction is pending government approval. The transaction will increase Statoil's ownership interest from 24% to 55% when completed. JX remains the operator with a 45% interest.

3.7 Marketing, Midstream and Processing (MMP)

3.7.1 MMP overview

Marketing, Midstream and Processing (MMP) is responsible for marketing and trading of crude oil, natural gas, gas liquids, refined products, for transportation and processing of commodities and for operation of refineries, terminals and processing plants.

MMP markets Statoil's own volumes, the Norwegian state's direct financial interest (SDFI) equity production of crude oil and third-party volumes, approximately 50% of all Norwegian liquids exports. MMP is also responsible for marketing SDFI's gas. In total, Statoil is responsible for marketing approximately 70% of all Norwegian gas exports. See sections 3.12.3 *The Norwegian State's participation* and 3.12.4 *SDFI oil and gas marketing and sale* for further details regarding the Norwegian state's direct financial interest.

MMP operates two refineries, two gas processing plants, one LNG plant (from 1 January 2016), one methanol plant and three crude oil terminals. In addition, MMP is responsible for developing transportation solutions for natural gas, liquids and crude oil from the Statoil assets including pipelines, shipping, trucking and rail.

In 2015, MMP sold 36.9 billion cubic metres (bcm) of natural equity gas from the Norwegian continental shelf (NCS) on our own behalf, in addition to approximately 37.2bcm of NCS gas on behalf of the Norwegian state. Statoil's total US gas sales, including third-party gas, amounted to 11.2 bcm in 2015. In 2015, MMP also sold 644 million barrels of crude oil and condensate, approximately 15 million tonnes of natural gas liquids (NGL), and approximately 1.2 million tonnes of methanol. Of the total 644 million barrels sold in 2015, approximately 50% represented Statoil equity volumes, while approximately 37% of the total 15 million tonnes of NGL sold in 2015 were Statoil equity volumes.

In 2015 the European gas market was characterised by falling prices due to record supplies and stagnating demand. Statoil's overall gas production increased somewhat compared to 2014. In the US the cold winter in North East US and Canada created large regional arbitrage margins. The LNG market showed continued regional price differences and geographical arbitrage margins. An oversupplied oil market globally has resulted in weak oil prices in 2015.

Refinery margins were higher than in 2014. Facilities have been operated with good regularity. HSE results are at the same level as in 2014 for Serious Incident Frequency (SIF) and Total Recordable Incident Frequency (TRIF), while there has been an increase in number of oil and gas leakages mainly due technical and operational issues. With effect from 1 June 2015, the Renewable Energy business cluster was transferred from MMP to New Energy Solutions (NES). The remaining business activities are organised in the following business clusters: Marketing and Trading; Asset Management and Processing and Manufacturing.

Key events in 2015:

- The operatorship for Azerbaijan Gas Supply Company and the commercial operatorship for South Caucasus Pipeline Company were transferred from Statoil to The State Oil Company of Azerbaijan Republic (SOCAR) effective from 1 May 2015 following the completion of the sale of Statoil's shares to SOCAR, BP and PETRONAS in 2014
- Following the divestment of its share in the Shah Deniz gas field in Azerbaijan, Statoil agreed to sell its 20% interest in Trans Adriatic Pipeline AG (TAP) to the Italian gas infrastructure company Snam
- Edvard Grieg oil pipeline and Utsira High gas pipeline became operational late 2015 and provide export of oil and gas for the Edvard Grieg field and in the future also for the Ivar Aasen field currently under construction
- The 482 kilometer long Polarled pipeline was laid at the Aasta Hansteen field at a depth of 1,260 meters in the Norwegian Sea
- Statoil signed an agreement with Centrica in May to increase the volume of gas supplies under an existing supply agreement. The gas supplied to the UK from the ten year agreement will increase from 5 bcm/year to 7.3 bcm/year from October 2015
- Statoil extended gas supply agreement with UK's SSE. Starting 1 October 2015, the gas supplied from the six year agreement will increase from approximately 0.5 bcm/year to approximately 2.5 bcm/year

The profitability of our industry continues to be challenged. Statoil's response to the industrial challenge characterised by escalating cost and declining returns is addressed in the Section *Strategy and market overview*.

3.7.2 Marketing and Trading

The Marketing and Trading business cluster (MT) is responsible for the marketing and trading of all the products from Statoil's upstream, processing and refining business.

3.7.2.1 Marketing and trading of gas and LNG

MMP is responsible for Statoil's marketing and trading of natural gas worldwide, for power and emissions trading and for overall gas supply planning and optimisation, including the SFDI.

The gas marketing and trading business is conducted from Norway (Stavanger) and from offices in Belgium, the UK, Germany and the US.

Statoil transports and markets approximately 70% of all NCS gas and continues to develop its position in the US.

A significant proportion of Statoil's gas sales are sold under long-term contracts. These sales are carried out with large industrial customers, power producers and local distribution companies. Gas is also sold through short-term contracts and through trading on European and US liquid marketplaces. In the US, gas is sold through bilateral contracts.

A few of Statoil's long-term gas contracts contain contractual price review mechanisms that can be triggered by the buyer or seller at regular intervals, or under certain given circumstances. Statoil is currently in price reviews with some of its customers.

Statoil expects to continue to optimise the market value of the gas delivered to Europe through a mix of long-term contracts and short-term marketing and trading. This is done both as a response to customer needs and in order to capture new business opportunities as the markets become more liberalised and liquid. Statoil has flexibility in terms of production and transportation systems. Combined with its downstream assets this is used to optimise the value of the gas sold.

Europe
The major export markets for gas from the NCS are Germany, France, the UK, Belgium, the Netherlands, Italy and Spain. Our longer term customers include large national or regional gas companies such as ENGIE, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), RWE and GasTerra.

Our European gas trading business conducts activities with over 85 counterparties on all European liquid trading locations. MMP is active on both physical and exchange markets such as Intercontinental Exchange (ICE).

US
The US is the world's largest and most liquid gas market. Statoil Natural Gas LLC (SNG), a wholly-owned subsidiary, has a gas marketing and trading organization in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power generators.

SNG also markets the gas equity production from Statoil's assets in the US Gulf of Mexico.

Statoil's entry into the Marcellus and the Eagle Ford shale gas plays has resulted in a significant increase in the volume of gas marketed and traded by Statoil in the US over the last few years.

SNG has entered into gas transportation agreements which enable Statoil to transport some of the produced gas from the Northern Marcellus production area to Manhattan, NY and to the US/Canadian border at Niagara, providing access to the greater Toronto area in Canada.

In addition SNG has long-term capacity contracts with Dominion Resources Inc., which owns the Cove Point LNG re-gasification terminal in Maryland, with a total capacity of 10.4 bcm per year. LNG is sourced from the Snøhvit LNG facility in Norway. Due to continuing low gas prices in the US, most of Statoil's LNG cargoes have been diverted away from the US and delivered into higher-priced markets in Europe, South-America and Asia.

Algeria
Statoil has a participating interest in the In Salah gas field, Algeria's third-largest gas development. The field is operated by a joint venture constituted by Statoil, BP and Sonatrach. Statoil receives its income from gas which is sold under long-term contracts.

3.7.2.2 Marketing and trading of liquids

MMP is responsible for the sale of the group's and the Norwegian state's direct financial interest (SDFI) production of crude oil and natural gas liquids.

Statoil is among the world's major net sellers of crude oil. The company operates from sales offices in Stavanger, Oslo, London, Singapore, Stamford and Calgary and markets and trades crude oil, condensate, NGLs as well as refined products.

The main crude oil market for Statoil is northwest Europe. Most of the crude oil volumes are sold in the spot market, based on publicly quoted market prices.

The liquids marketing and trading business is responsible for commercial optimisation of the Mongstad and Kalundborg refineries as well as crude terminals located at Mongstad, Sture and South Riding Point in the Bahamas. MMP is also responsible for Statoil's liquefied petroleum gas (LPG) liftings at the Sture terminal, as well as Statoil's naphtha lifting from Kårstø and Braefoot Bay, liftings of LPG from Kårstø, Mongstad, Braefoot Bay and Teesside terminals in addition to marketing of condensate and LPG from the In Amenas field In Algeria. Statoil lifts waterborne ethane from Kårstø and Teesside, condensate from Nyhamna, and condensate and LPG volumes from Melkøya.

In addition, MMP markets equity crude oil, condensate and NGL production from Statoil's unconventional assets in North America. They include the Alberta oil sands, Bakken, Eagle Ford, and Marcellus. Unconventional volumes were mostly sold in the spot market based on publicly quoted prices. Production from Eagle Ford is primarily transported by pipeline while the most part of crude oil from Bakken is transported to the best paying markets by rail.

MMP also markets equity volumes from DPI assets located in Canada, US, Brazil, Angola, Nigeria, Algeria, Russia, Azerbaijan and UK, as well as third party volumes.

Value is maximised through the use of own and leased capacity such as terminals, storages, pipelines, railcars and vessels.

3.7.3 Asset Management

The Asset Management business cluster (AM) is the owner of all mid- and downstream assets in Statoil, ranging from refineries to pipelines, storage terminals, shipping activities and other infrastructure lease commitments.

AM is responsible for securing flow assurance for gas and oil in order to bring production to the markets. This includes management and development of existing assets and contracts as well as being responsible for Statoil's mid and downstream investment projects. Furthermore AM ensures that the Marketing and Trading business cluster (MT) has efficient access to assets for trading purposes.

3.7.3.1 Production plants

AM is the owner of Statoil`s two refineries in Norway and Denmark and a combined heat and power plant in Norway. AM manages Statoil`s majority ownership share of a methanol production plant, as well as Statoil`s minority share in an NGL and condensate processing facility.

Mongstad
Statoil holds 100% ownership and is operator of the Mongstad refinery in Norway. The refinery was built in 1975, and significantly expanded and upgraded in the late 1980s. In addition it has been subject to considerable investments over the last 15 years in order to meet new product specifications and to improve energy efficiency. The refinery is a medium-sized, modern refinery, with a crude oil and condensate distillation capacity of 226,000 barrels per day.

The refinery is directly linked to offshore fields through two crude oil pipelines, through a natural gas liquids (NGL)/condensate pipeline to the crude oil terminal at Sture and the gas processing plant at Kollsnes, and by a gas pipeline to Kollsnes, making it an attractive site for landing and processing of hydrocarbons.

In addition to the refinery, the main facilities at Mongstad consist of a crude oil terminal (Mongstad terminal), an NGL processing unit and terminal (Vestprosess), and a combined heat and power plant (Mongstad Heat and Power Plant).

Statoil owns 34% of Vestprosess, which transports and processes NGL and condensate. The Vestprosess pipeline connects the Kollsnes and Sture plants to Mongstad. The NGL is fractionated in the Vestprosess NGL unit to produce naphtha, propane and butane.

Statoil is the owner of Mongstad Heat and Power Plant, which produces electrical heat and power from gas received from Kollsnes and from the refinery. The combined heat and power plan started commercial operation in 2010 and improved the Mongstad refinery's energy efficiency. It has a capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat.

Kalundborg
Statoil holds 100% ownership and is operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 108,000 barrels per day. The Kalundborg refinery is a small, carbon dioxide efficient and flexible oil refinery. While this enables it to produce a variety of products, its main products are low-sulphur gasoline and diesel for markets in Denmark and Sweden. The refinery is connected via one gasoline and one gas oil pipeline to the terminal at Hedehusene near Copenhagen, and most of its products are sold locally.

Tjeldbergodden
The methanol plant at Tjeldbergodden, the largest in Europe, receives natural gas from the Heidrun field in the Norwegian Sea through the Haltenpipe pipeline. Statoil has an ownership interest of 82,0% in Statoil Metanol ANS at Tjeldbergodden. In addition, Statoil holds a 50.9% ownership interest in Tjeldbergodden Luftgassfabrikk DA, which is one of the largest air separation units (ASU) in Scandinavia.

3.7.3.2 Terminals and storage

AM has ownership in two crude oil terminals in Norway. AM also operates the South Riding Point crude oil terminal in the Bahamas.

Mongstad terminal
Statoil has a 65% ownership interest in Mongstad crude oil terminal, while the State holds 35%. Crude oil is landed at Mongstad via two pipelines from Troll and by crude tankers from the market. The Mongstad terminal has a storage capacity of 9.4 million barrels of crude oil. The terminal supports Statoil's global trading, blending and trans-shipment of crude. It is an important tool in the marketing of North Sea crude.

Sture terminal
The Sture crude oil terminal receives crude oil via two pipelines from the Oseberg and Grane areas in the North Sea. The terminal is part of the Oseberg Transportation System (Statoil interest 36.2%). The processing facilities at Sture stabilise Oseberg crude oil and recover LPG mix (propane and butane) and naphtha. Oseberg blend, Grane blend and LPG mix are exported. LPG and naphtha are also transported through the Vestprosess pipeline to Mongstad.

South Riding Point terminal
AM operates the South Riding Point Terminal, which is located on Grand Bahamas Island, and consists of two shipping berths and ten storage tanks of crude oil, with a storage capacity of 6.75 million barrels of crude oil. The terminal has been upgraded to also enable the blending of crude oils, including heavy oils. The blending is carried out onshore and from ship to ship at the jetty. The terminal is intended to both support our global trading activity and improve our handling capacity for heavy oils. The terminal is an integral part of our marketing of equity volumes of heavy oil.

Aldbrough Gas Storage
Statoil UK holds one third share of the interests in the Aldbrough Gas Storage in UK, operated by SSE Hornsea Ltd. At the end of 2015 six out of nine caverns were operational.

Etzel Gas Lager
Statoil Deutschland Storage GmbH holds a 23.7% stake in the Etzel Gas Lager in North Germany which has a total of nineteen caverns and secures regularity for gas deliveries from the NCS.

Teesside terminal
Statoil UK holds a 27.3% stake in the Teesside terminal, which stabilises unstable oil from the Ekofisk area and several other Norwegian and UK fields and recovers NGL.

3.7.3.3 Pipelines

AM is responsible for Statoil's ownership in pipelines globally as well as gathering and initial processing in the US.

Pipelines in operations
Statoil is a significant shipper in the NCS gas pipeline system. This network links gas fields on the Norwegian continental shelf (NCS) with processing plants on the Norwegian mainland and with terminals at six landing points located in France, Germany, Belgium and the UK.

The total length of Norway's gas pipelines is currently 8,100 kilometres, and most gas pipelines on the NCS that are accessed by third-party customers are owned by a single joint venture, Gassled, with regulated third-party access. The Gassled system is operated by the independent system operator Gassco AS, which is wholly owned by the Norwegian state. When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted to reflect each owner's relative interest. Hence, Statoil's future ownership interest in Gassled may change. AM is managing Statoil's current 5% ownership share in Gassled.

In addition AM manage Statoil's ownership in the following pipelines in the Norwegian gas transportation system: Oseberg oil transportation system, Grane oil pipeline, Kvitebjørn oil pipeline, Troll oil pipeline I and II, Edvard Grieg oil pipeline, Utsira High gas pipeline, Valemon rich gas pipeline, Haltenpipe,Norpipe and Mongstad gas pipeline.

Statoil Deutschland GmbH indirect holds a 30.8% stake in the Norddeutche Erdgas Transversale (NETRA) overland gas transmission pipeline.

Pipelines under construction
Statoil is the operator and holds a 37.1% ownership share in the Polarled project which will secure a gas export pipeline for fields in the Norwegian Sea. The project is aligned with the Aasta Hansteen field development.

Statoil is the operator and holds a 40% ownership share in the Johan Sverdrup oil and gas pipelines. The pipelines will provide oil and gas export for the Johan Sverdrup field and is scheduled to start-up in 2019.

In the fourth quarter of 2015 Statoil entered into an agreement with Snam to sell our 20% interest in the Trans Adriatic Pipeline (TAP). See note 4 *Acquistitions and dispositions* for further details.

US gathering system
AM is responsible for Statoil's participation in gathering and facilities for initial processing of oil and gas in the Bakken, Eagle Ford and Marcellus assets in the US. This includes crude and natural gas gathering systems, fresh water supply systems, salt water disposal wells, oil and gas treatment and processing facilities to provide flow assurance for Statoil's upstream production. Midstream assets in Bakken are owned and operated 100% by Statoil. In Eagle Ford, Statoil will transition to operator for 100% of the midstream assets outside of the Oak, Karnes, DeWitt and Bee (KDB) area with a working interest of 63%. In the KDB area of Eagle Ford, Statoil has an ownership interest of 25.2% in Edwards Lime Gathering LLC, which is operated by Energy Transfer Partners L.P. For Marcellus Statoil has operated assets in Marcellus South while in the Marcellus non-operated areas both in the North and South, Statoil's working interest ranges from 16.25% to 32.5% depending on gathering system and number of JV partners.

3.7.4 Processing and Manufacturing

The Processing and Manufacturing business cluster (PM) is responsible for the operation of all of Statoil's onshore facilities in Norway and Denmark except for Snøhvit related facilities, and a substantial part of the oil and gas pipelines on the NCS.

This includes the following Statoil operated plants and pipelines: The refineries at Mongstad and Kalundborg, the methanol production plant at Tjeldbergodden, Oseberg transportation system including the Sture Terminal, Vestprosess, Mongstad Terminal, the Grane, Kvitebjørn, Troll and Edvard Grieg oil pipelines and Mongstad gas pipeline.

The following table shows operating statistics for the plants at Mongstad, Kalundborg and Tjeldbergodden.

	Throughput[1]			Distillation capacity[2]			On stream factor %[3]			Utilisation rate %[4]		
Refinery	2015	2014	2013	2015	2014	2013	2015	2014	2013	2015	2014	2013
Mongstad	**11.9**	9.2	11.8	**9.3**	9.3	9.3	**97.6**	93.4	98.9	**93.4**	90.0	95.0
Kalundborg	**5.2**	4.5	5.0	**5.4**	5.4	5.4	**98.5**	91.8	98.2	**91.0**	82.0	86.5
Tjeldbergodden	**0.92**	0.83	0.79	**0.95**	0.95	0.95	**98.5**	88.4	94.4	**98.5**	97.1	96.6

1) Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes.
Higher than distillation capacity for Mongstad due to high volumes of fuel oil and NGL not going through the crude distillation unit.
Higher than distillation capacity for Kalundborg, due to volumes of kero, naphta, gasoil and biodiesel-additive not going through the crude-/condensate units.
2) Nominal crude oil and condensate distillation capacity, and methanol production capacity, measured in million tonnes.
3) Composite reliability factor for all processing units, excluding turnarounds.
4) Composite utilisation rate for all processing units, stream day utilisation.

In addition PM performs the role of technical service provider (TSP) for the Kårstø and Kollsnes gas processing plants in accordance with the technical service agreement between Statoil and the operator Gassco. PM also performs the TSP role for the larger share of the Gassco operated gas pipeline infrastructure.

The processing that takes place at Kollsnes involves separating out the NGL, and compressing the dry gas for export via the Gassled pipeline network to receiving terminals in Europe. The Kollsnes plant was initially developed to receive gas from the Troll field. Kollsnes now also receives gas from the Visund, Kvitebjørn and Fram fields.

Kårstø processes rich gas and condensate from the NCS received via the Statpipe pipeline, the Åsgard Transport pipeline and the Sleipner condensate pipeline. Products produced at Kårstø include ethane, propane, iso-butane, normal butane, naphtha and stabilised condensate. The dry gas is transported to customers through the Gassled pipeline network via receiving terminals in Europe.

As of 1 January 2016 responsibility for operation of Snøhvit onshore facilities has been transferred from DPN to MMP.

For further information about Statoil's operated onshore facilities and pipelines see section 3.7.3 *Asset Management.*

3.8 Other Group

The Other reporting segment includes activities in New Energy Solutions (NES), Global Strategy and Business Development (GSB), Technology, Projects and Drilling (TPD) and corporate staffs and support functions.

3.8.1 New Energy Solutions (NES)

The NES business area reflects Statoil's aspirations to gradually complement its oil and gas portfolio with profitable renewable energy and other low-carbon energy solutions. Offshore wind and carbon capture and storage have been key focus areas in 2015.

In February 2016, Statoil launched a new energy investment fund dedicated to investing in attractive and ambitious growth companies in renewable energy, supporting its strategy of growth in new energy solutions. The new fund, Statoil Energy Ventures, will invest up to USD 200 million over a period of four to seven years.

Key events in 2015:
- In October Statoil made a final investment decision to build the world's first floating offshore wind park: The Hywind pilot park, to be located outside Peterhead in Scotland
- In June Statoil announced that that it would establish NES as a new business area to create new profitable solutions within renewable energy and other low-carbon solutions, combining Statoil's oil and gas portfolio, project delivery capacity and ability to integrate technological solutions. As a starting point the existing offshore wind portfolio constitutes the main activities in this area. The ambition is to grow and potentially expand into other sources of renewable energy

Sheringham Shoal
The Sheringham Shoal wind farm, located off the coast of Norfolk, UK, was formally opened in September 2012. The wind farm is in full production with 88 turbines and an installed capacity of 317 megawatt (MW). Following divestment in 2014, it is now owned 40% by Statkraft, a Norwegian wholly state-owned company, 40% by Statoil and 20% by the UK Green Investment Bank (GIB). The wind farm's annual production is approximately 1.1 terawatt hours (TWh) and it has the capacity to provide power to approximately 220,000 households.

Dudgeon offshore wind project
Statoil acquired a 70% share in the Dudgeon offshore wind farm project in October 2012 together with Statkraft (30%). In 2014 Statoil reduced its share to 35%, bringing in Masdar as a new partner. The project is located in the Greater Wash Area off the English east coast, not far from Sheringham Shoal. A final investment decision for the 402 MW project was made in July 2014. All construction contracts are awarded and construction has started. The wind farm is expected to produce 1.7 TWh yearly from 67 turbines, with the capacity to provide power for approximately 410,000 households. It is expected to be in full operation by year end 2017.

Dogger Bank
Statoil and Statkraft, together with RWE and SSE, are partners in the Forewind consortium, each with a 25% equity stake. The Dogger Bank area has a total consented capacity of 4.8 GW, and is potentially the largest offshore wind farm development in the world. The consortium received consent for four projects, each with a capacity of 1200 MW by the UK Government in February and August 2015.

Hywind
The world's first full-scale floating offshore wind turbine has been in operation as a demonstration facility off the coast of Karmøy for six years. Hywind's overall performance has exceeded expectations and has experienced several storms with extreme wind of over 40m/s and maximum waves of 19 m height without any damage influencing technical integrity of the structure or turbine. Statoil is continuously working on improving the operating model. Statoil`s strategy has been to utilise the experience gained from this demo project to develop a floating wind park pilot, which Statoil has achieved with Hywind Scotland.

Hywind Scotland pilot project
Hywind Scotland is a floating wind pilot park using the Hywind concept developed and owned by Statoil. The business case is to demonstrate cost-efficient and low risk solutions for commercial scale parks. This will be done by verifying the use of larger Wind Turbine Generators (WTG), optimising the design and demonstrating scale effects in a wind farm layout. Statoil will install 5 Siemens 6.0MW turbines, a total capacity of 30MW. The project is located at Buchan Deep, approximately 25 km off Peterhead on the West coast of Scotland. Production is expected to be 0.14 TWh/year. The project was sanctioned in October 2015 and planned first deliveries to the grid is fourth quarter 2017. This is the next step in our strategy towards deployment of our first utility scale floating wind farms.

Carbon capture and Storage (CCS)
Since 1996 Statoil has proven experience in CCS and has continued to develop competence through research engagement in the Technical Centre Mongstad (TCM) and offshore operations in Sleipner and Snøhvit. Statoil will seek to deploy our competence and experience in other CCS projects, continue to evaluate opportunities to reduce carbon dioxide emissions and explore carbon dioxide for enhanced oil recovery (EOR) possibilities.

3.8.2 Global Strategy and Business Development (GSB)

The Global Strategy and Business Development (GSB) business area is Statoil's functional centre for strategy and business development.

GSB is responsible for Statoil's global strategy processes, and identifies, develops and delivers inorganic business development opportunities. This is achieved through close collaboration across geographic locations and business areas. Statoil's strategy forms the basis for guiding the company's business development focus.

GSB's business activities are organised in the following areas:
- **Corporate strategy and analysis:** Managing corporate strategy development processes, competitor intelligence, industry analysis
- **Political Analysis:** Monitoring political developments nationally, regionally and globally. The unit assesses geopolitical issues and trends impacting our business, political risk related to specific countries and projects, and changes to the broader security threat picture
- **Corporate Sustainability:** Shaping Statoil's strategic response to sustainability issues, development of relevant policies and reporting on the company's sustainability performance
- **Business Development Origination**: Identifying and originating business development opportunities, sharing on-the-ground context and intelligence across the organisation
- **Mergers, Acquisitions and Divestments**: Executing of business development and merger/corporate acquisition/divestment options, sharing deal activity context and intelligence across the organisation
- **Project Support and Execution**: Commercial negotiation support, commercial and technical valuation, business development best practice

3.8.3 Technology, Projects and Drilling (TPD)

Technology, Projects and Drilling (TPD) business area is responsible for delivering projects and wells and providing global support on standards and procurement. TPD is also responsible for developing Statoil as a technology company.

Key events in 2015:
- 117 offshore wells were delivered, including 29 exploration wells
- Drilling efficiency has been significantly enhanced over the last three years. During 2015, the average number of metres drilled per day increased 25% from 2014
- Valemon came on stream: Statoil's first platform to be controlled remotely from shore. Once drilling is completed, the platform will transform into a normally unmanned platform
- The first subsea gas compression plant in the world was brought on line at Åsgard. Another subsea gas compression plant is being developed at Gullfaks
- Fast-track projects Oseberg Delta 2, Smørbukk South extension and Gullfaks South improved oil recovery were brought on stream
- The construction of the fast-track project Gullfaks Rimfaksdalen started
- Three major pipelays were completed: Polarled gas pipeline, Edvard Grieg oil export pipeline and Utsira high gas export pipeline
- The world's largest system for four-dimensional permanent reservoir monitoring was installed at Snorre and Grane, improving the oil recovery rate. 700 kilometres of seismic cables were installed on the seabed
- Two new compressors were brought on line on the Troll A platform
- A new floating storage vessel was brought into operation at Heidrun
- The development of Aasta Hansteen, Gina Krog and Mariner fields continued through 2015
- The construction of the Johan Sverdrup project started. In 2015, contracts worth more than NOK 50 billion were awarded
- The plan for development and operation of Oseberg Vestflanken 2 was submitted to the Ministry of Petroleum and Energy. The field is being developed using an unmanned wellhead platform, a new, cost-effective solution in Statoil's field development toolbox
- A decision was made to develop Hywind Scotland pilot park. The commercial scale, floating wind farm is being developed using Hywind, a floating wind turbine concept developed and owned by Statoil. The construction of Dudgeon offshore wind farm progressed through 2015
- There has been a certain overcapacity in the offshore rig portfolio owing to reduced demand and increased efficiency
- 18 specific and profitable projects aimed at reducing the environmental footprint have been established under the General Electric/Statoil powering collaboration, launched in 2015
- During 2015, 101 new technologies were developed. 20 selected high-value technologies were implemented in 59 different locations, a 50% increase from 2014
- Statoil has captured significant market effects through renegotiating and rebidding most of the agreement portfolio with suppliers during 2015

From 1 January 2016, Statoil has gathered all project expertise in TPD, into one integrated, cost-effective Project Development organisation (PRD), to ensure lean and effective execution and decision-making. From the same date, Technology Excellence and Research, Development and Innovation were merged into one integrated Research and Technology organisation (R&T), reinforcing innovation and technology effectiveness.

TPD business activities were in 2015 organised in the following business clusters:

Research, Development and Innovation (RDI)
RDI is responsible for carrying out research and technology development to meet Statoil's business needs on short and long term.

RDI is organised in four research programmes closely aligned with Statoil's technology strategy: Exploration, Mature area developments and improved oil recovery, Frontier developments and Un-conventionals. In addition, there are two other units: Innovation and Projects. RDI has four research centres in Norway with world-leading laboratories and large-scale test facilities. Internationally, RDI is currently active in our operations in Rio de Janeiro (Brazil), Houston and Austin (the US), St. Johns (Canada) and Beijing (China). Cooperation with external environments plays an important role for R&D in Statoil, and RDI has an Academia programme which coordinates cooperation with Norwegian and international universities.

Technology Excellence (TEX)
TEX is globally responsible for delivering technical expertise to projects, business developments and assets, and for implementing new technologies.

TEX is responsible for driving simplification and standardisation and delivers technological expertise within the areas of petroleum, subsea and marine, facilities and operations, and safety and sustainability technologies enhancing Statoil's operational performance. Technology development and implementation are used to achieve corporate targets for production growth, improved efficiency and regularity, reserve growth and reduced costs. Through Statoil technology invest (STI), TEX supports innovators and entrepreneurs with technology development and commercialisation activities.

Projects (PRO)
PRO is responsible for planning and executing all major facilities development, modification and field decommissioning projects in Statoil.

The project portfolio is diverse, ranging from major new field developments to both small and large development projects on the NCS and internationally. During 2015, around 50 projects were in the execution phase, and at year-end, 30 projects were in the early phase. The proportion of larger projects in the portfolio has increased over the last three years.

Drilling and Well (D&W)
D&W is responsible for providing cost-efficient well delivery, ensuring fit-for-purpose drilling facilities and providing expertise and advice to Statoil's global drilling and well operations.

D&W operated 35 rig years in 2015, compared to 40 in 2014, and delivered production and exploration wells offshore on the NCS and Brazil, and exploration wells in Canada, the Gulf of Mexico, Tanzania and the UK.

Procurement and Supplier Relations (PSR)
PSR is responsible for global procurement aligned with Statoil's business needs, and for managing Statoil's supply chain. Statoil's procurements originate from approximately 12,000 active suppliers.

The procurement process is based on competition and the principles of openness, non-discrimination and equality. PSR encourages and facilitates collaboration with suppliers through communication and by managing supplier relations. By maintaining strong relations with high-quality suppliers, Statoil aims to ensure lasting, long-term competitive advantages. PSR has a strategy for increasing diversity, competition and flexibility in the market to better utilise industry capacity and expertise.

3.8.4 Corporate staffs and support functions

Corporate Staffs and support functions comprise the non-operating activities supporting Statoil.

They include headquarters and central functions that provide business support such as corporate communication, safety, audit, legal services and people and organisation.

3.9 Significant subsidiaries

The following table shows significant subsidiaries and equity accounted companies as of 31 December 2015.

Our voting interest in each company is equivalent to our equity interest.

Ownership in certain subsidiaries and other equity accounted companies

Name	in %	Country of incorporation	Name	in %	Country of incorporation
Statholding AS	100	Norway	Statoil Nigeria Deep Water AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil Nigeria Outer Shelf AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 38 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Angola Block 39 AS	100	Norway	Statoil OTS AB	100	Sweden
Statoil Angola Block 40 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Shah Deniz AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil Tanzania AS	100	Norway
Statoil Danmark AS	100	Denmark	Statoil Technology Invest AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil UK Ltd	100	United Kingdom
Statoil do Brasil Ltda	100	Brazil	Statoil Venezuela AS	100	Norway
Statoil Exploration Ireland Ltd.	100	Ireland	Statoil Venture AS	100	Norway
Statoil Forsikring AS	100	Norway	Statoil Metanol ANS	82	Norway
Statoil Færøyene AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Hassi Mouina AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Indonesia Karama AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil New Energy AS	100	Norway	Naturkraft AS	50	Norway
Statoil Nigeria AS	100	Norway	Vestprosess DA	34	Norway

3.10 Production volumes and prices

The business overview is in accordance with our segment's operations as of 31 December 2015, whereas certain disclosures on oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC).

For further information about extractive activities, see sections 3.5 *Development and Production Norway* and 3.6 *Development and Production International*, respectively.

Statoil prepares its disclosures for oil and gas reserves and certain other supplemental oil and gas disclosures by geographical area, as required by the SEC. The geographical areas are defined by country and continent. They are Norway, Eurasia excluding Norway, Africa and the Americas.

For further information about disclosures concerning oil and gas reserves and certain other supplemental disclosures based on geographical areas as required by the SEC, see section 3.11 *Proved oil and gas reserves*.

3.10.1 Entitlement production

This section describes our oil and gas production and sales volumes.

The following table shows Statoil's Norwegian and international entitlement production of oil and natural gas for the periods indicated. The stated production volumes are the volumes to which Statoil is entitled, pursuant to conditions laid down in licence agreements and production-sharing agreements. The production volumes are net of royalty oil paid in kind, and of gas used for fuel and flaring. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas. Production of an immaterial quantity of bitumen is included as oil production. NGL includes both LPG and naphtha. The only field containing more than 15% of total proved reserves based on oil equivalent barrels is the Troll field. For further information on production volumes see section 9 *Terms and definitions*.

	For the year ended 31 December		
Entitlement production	2015	2014	2013
Norway			
Oil and Condensate (mmbbls)	174	173	174
NGL (mmbbls)	44	42	42
Natural gas (bcf)	1,306	1,229	1,264
Combined oil, condensate, NGL and gas (mmboe)	450	434	441
Eurasia excluding Norway			
Oil and Condensate (mmbbls)	13	14	15
Natural gas (bcf)	16	56	72
Combined oil, condensate, NGL and gas (mmboe)	16	24	28
Africa			
Oil and Condensate (mmbbls)	75	64	58
NGL (mmbbls)	3	2	1
Natural gas (bcf)	63	38	40
Combined oil, condensate, NGL and gas (mmboe)	88	72	66
Americas			
Oil and Condensate (mmbbls)	62	55	50
NGL (mmbbls)	7	7	4
Natural gas (bcf)	215	242	196
Combined oil, condensate, NGL and gas (mmboe)	107	106	89
Total			
Oil and Condensate (mmbbls)	324	306	298
NGL (mmbbls)	54	51	47
Natural gas (bcf)	1,600	1,565	1,571
Combined oil, condensate, NGL and gas (mmboe)	662	635	625
Troll field 1)			
Oil and Condensate (mmbbls)	14	14	14
NGL (mmbbls)	2	2	2
Natural gas (bcf)	386	317	304
Combined oil, condensate, NGL and gas (mmboe)	85	73	70

1) Note that Troll is also included in Norway stated above.

3.10.2 Sales prices

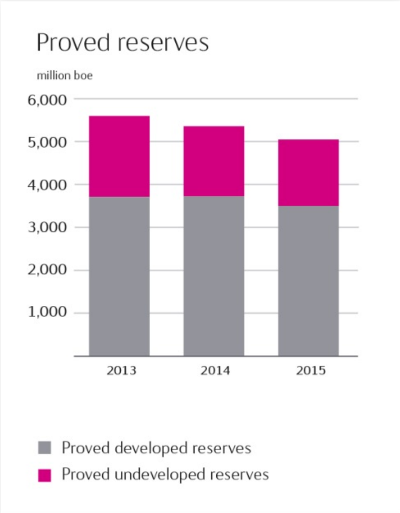
The following tables present realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 2015				
Average sales price oil and condensate in USD per bbl	52.2	50.7	49.4	39.4
Average sales price NGL in USD per bbl	30.1	-	26.2	12.5
Average sales price natural gas in NOK per Sm3	2.2	1.4	1.7	0.8
Year ended 31 December 2014				
Average sales price oil and condensate in USD per bbl	98.3	101.3	95.6	78.3
Average sales price NGL in USD per bbl	59.3	-	59.7	37.3
Average sales price natural gas in NOK per Sm3	2.3	1.3	2.2	1.0
Year ended 31 December 2013				
Average sales price oil and condensate in USD per bbl	109.1	110.5	107.3	89.1
Average sales price NGL in USD per bbl	67.4	-	69.7	59.2
Average sales price natural gas in NOK per Sm3	2.4	0.9	2.1	0.8

3.11 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,060 mmboe at year end 2015, compared to 5,359 mmboe at the end of 2014.

Statoil's proved reserves are estimated and presented in accordance with the Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X, revised as of January 2009, and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. For additional information, see section Proved oil and gas reserves in note 2 *Significant accounting policies* to the Consolidated financial statements. For further details on proved reserves, see also note 27 *Supplementary oil and gas information (unaudited)* in the Consolidated financial statements.



Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of new development projects. These are sources of additions to proved reserves that are the result of continuous business processes and can be expected to continue to add reserves in the future.

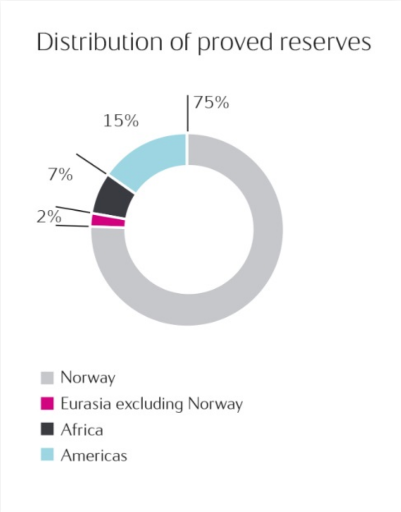
Proved reserves can also be added or subtracted through the acquisition or disposal of assets. Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. Lower oil and gas prices normally allow less oil and gas to be recovered from the accumulations. However for fields with production sharing agreements (PSAs) and similar contracts a reduced oil price may result in higher entitlement to the produced volume. These changes are included in the revisions category in the table below.

The principles for booking proved gas reserves are limited to contracted gas sales or gas with access to a robust gas market.

In Norway and the UK, Statoil recognises reserves as proved when a development plan is submitted, as there is reasonable certainty that such a plan will be approved by the regulatory authorities. Outside these territories, reserves are generally booked as proved when regulatory approval is received, or when such approval is imminent. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years. Undrilled well locations onshore are generally booked as proved undeveloped reserves when a development plan has been adopted and the well locations are scheduled to be drilled within five years,

Approximately 89% of our proved reserves are located in OECD countries. Norway is by far the most important contributor in this category, followed by the United States of America (US), Canada, Ireland and the United Kingdom (UK).

Of Statoil's total proved reserves, 9% are related to production-sharing agreements (PSAs) in non-OECD countries such as Azerbaijan, Angola, Algeria, Nigeria, Libya and Russia. Other non-OECD reserves are related to concessions in Brazil and Venezuela, representing less than 3% of Statoil's total proved reserves. These are included in proved reserves in the Americas.



Significant changes in our proved reserves in 2015 were:

- Negative revisions due to lower commodity prices compared to last year, which resulted in a reduction of approximately 350 million boe. A large portion of this is related to undeveloped fields where lower commodity prices resulted in earlier economic cut-off, such as the Mariner field in the UK which is under development and is expected to start production in 2018, and uneconomic undeveloped well locations onshore US. The negative revisions are partly offset by positive revisions due to better performance of producing fields, maturing of improved recovery projects, and reduced uncertainty due to further drilling and production experience. The net effect of the positive and negative revisions is a reduction of 42 million boe in 2015. The estimated reduction due to change in prices is a rough estimate derived by using last year's prices on this year's volume base. In the calculation no adjustments have been made for the possible effect on the activity level, operating cost or development cost. For more information regarding prices see section 27 *Supplementary oil and gas information (unaudited)*
- Proved reserves from new discoveries have also been added through the sanctioning of new field development projects in 2015, Johan Sverdrup being the largest contributor. The new projects added a total of 476 million boe
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved reserves in 2015, and some of these additions are presented as extensions. Extension of proved area on existing field added a total of 150 million boe of new proved reserves in 2015
- The net effect of purchase and sale reduced the reserves by 221 million boe in 2015
- The 2015 entitlement production was 662 million boe, an increase of 4.3% compared to 2014. New discoveries with proved reserves booked in 2015 are all expected to start production within a period of five years

Summary of proved reserves as of 31 December 2015

	Proved reserves			
Reserves category	Oil and Condensate (mmboe)	NGL (mmboe)	Natural Gas (bcf)	Total oil and gas (mmboe)
Developed				
Norway	505	235	10,664	2,641
Eurasia excluding Norway	48	-	32	53
Africa	248	9	206	294
Americas	303	45	999	526
Total Developed proved reserves	1,104	290	11,901	3,515
Undeveloped				
Norway	711	56	2,278	1,173
Eurasia excluding Norway	29	-	161	57
Africa	30	6	160	64
Americas	217	12	124	251
Total Undeveloped proved reserves	987	74	2,723	1,546
Total proved reserves	2,091	364	14,624	5,060

Statoil's proved reserves of bitumen in the Americas are included as oil in the table above since they represent less than 2% of Statoil's proved reserves, which is regarded as immaterial.

The basis for equivalents is presented in the section *Terms and definitions*.

Reserves replacement

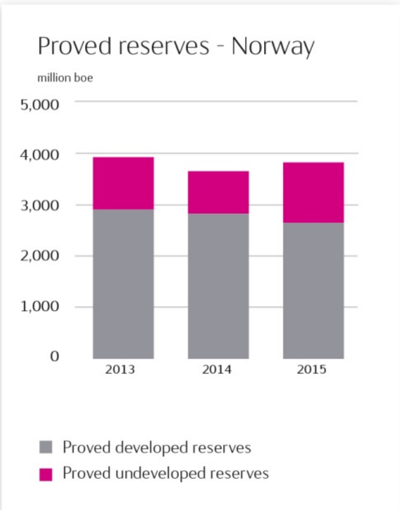
The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves divided by produced volumes in any given period. The following table presents the changes in reserves in each category relating to the reserve replacement ratio for the years 2015, 2014 and 2013.

	For the year ended 31 December		
(million boe)	2015	2014	2013
Revisions and improved recovery	(42)	356	395
Extensions and discoveries	627	253	523
Purchase of petroleum-in-place	13	20	14
Sales of petroleum-in-place	(235)	(233)	(131)
Total reserve additions	363	395	802
Production	(662)	(635)	(625)
Net change in proved reserves	(299)	(240)	177

The reserves replacement ratio for 2015 was 0.55 compared to 0.62 in 2014. The 2015 reserves replacement ratio, excluding purchases and sales of petroleum in place, was 0.88. The average replacement ratio for the last three years was 0.81, or 1.10 excluding purchases and sales.

	For the year ended 31 December		
Reserves replacement ratio (including purchases and sales)	2015	2014	2013
Annual	0.55	0.62	1.28
Three-year-average	0.81	0.97	1.15

The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, sensitivity related to the timing of project sanctions and the time lag between exploration expenditure and the booking of reserves.



Proved reserves in Norway

A total of 3,814 million boe is recognised as proved reserves in 58 fields and field development projects on the NCS, representing 75% of Statoil's total proved reserves. Of these, 54 fields and field areas are currently in production, 42 of which are operated by Statoil. Four new field development projects added reserves during 2015, Johan Sverdrup, Oseberg Vestflanken 2, Fram C-Øst Brent and Opal categorised as extensions and discoveries. Production experience, further drilling and improved recovery on several of Statoil's producing fields in Norway also contributed positively to the revisions of the proved reserves in 2015.

Sales of reserves are related to the agreement with Repsol. This has reduced Statoil's share of proved reserves on Gudrun.

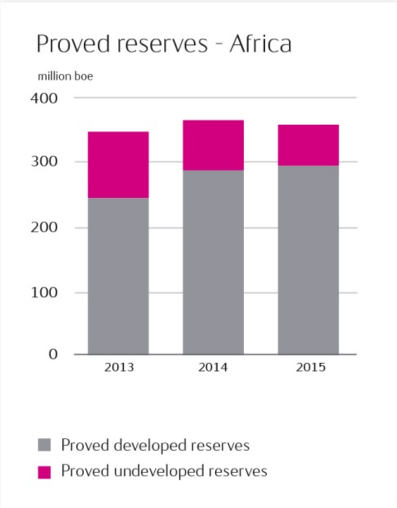
Of the proved reserves on the NCS, 2,641 million boe, or 69%, are proved developed reserves. Of the total proved reserves in this area, 60% are gas reserves related to large offshore gas fields such as Troll, Snøhvit, Oseberg, Ormen Lange, Tyrihans, Visund, Aasta Hansteen and Åsgard and 40% are liquid reserves.

Proved reserves in Eurasia, excluding Norway

In this area, Statoil has proved reserves of 111 million boe related to four fields and field developments in Azerbaijan, the UK, Ireland and Russia. Eurasia excluding Norway represents 2% of Statoil's total proved reserves, Azerbaijan being the main contributor with the Azeri-Chirag-Gunashli fields. All fields are producing. The effect of the farm out of Shah Deniz reduced the proved reserves at year end 2015.

Proved undeveloped reserves were reduced due to negative revisions linked to lower commodity prices resulting in earlier economic cut-off for the fields, primarily the Mariner field in the UK which is under development and is expected to start production in 2018.

Of the proved reserves in Eurasia, 53 million boe or 48% are proved developed reserves. Of the total proved reserves in this area, 69% are liquid reserves and 31% are gas reserves.



Proved reserves in Africa

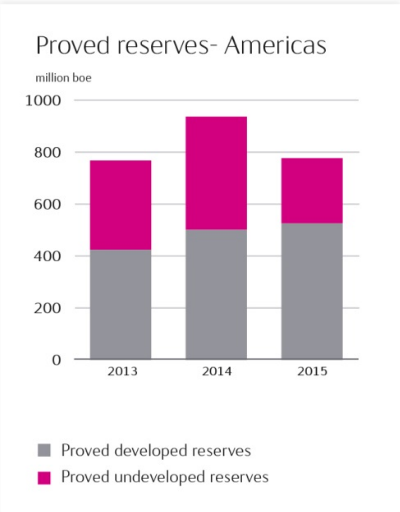
Statoil recognises proved reserves of 358 million boe related to 29 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 7% of Statoil's total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 24 of the 29 fields.

In Angola, Statoil has proved reserves in three blocks, Block 15, Block 17 and Block 31, with production from all blocks. During 2015 Statoil exited Block 4/05, Gimboa is therefore removed from proved reserves this year.

All fields are in production in Algeria and Nigeria. Murzuq and Mabruk are currently not producing due to the unrest in Libya.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.

Of the total proved reserves in Africa, 294 million boe, or 82%, are proved developed reserves. Of the total proved reserves in this area, 82% are liquid reserves and 18% are gas reserves.



Proved reserves in the Americas

In North and South America, Statoil has proved reserves equal to 777 million boe in a total of 17 fields and field development projects. This represents 15% of Statoil's total proved reserves. Ten of these fields are located in the US, seven of which are offshore field developments in the Gulf of Mexico and three are onshore tight reservoir assets. Five are located in Canada and two in South America.

In the US, four of the seven fields in the Gulf of Mexico are in production. Field development is ongoing on Big Foot, Heidelberg and Stampede. The onshore tight reservoir assets Marcellus, Eagle Ford and Bakken are all in production. In Canada, proved reserves are related both to offshore field developments, and to the Leismer field in the Kai Kos Dehseh oil sands project in Alberta.

Proved undeveloped reserves were reduced due to negative revisions linked to lower commodity prices, primarily resulting in undeveloped well locations onshore US becoming uneconomic.

Several transactions were completed during 2015, both purchases and sales. The largest were the transaction with Southwestern Energy reducing the reserves in Marcellus, and the agreement with Repsol increasing the reserves in Eagle Ford. The transactions offset each other and the net effect on proved reserves is zero.

Of the total proved reserves in the Americas, 526 million boe, or 68%, are proved developed reserves. Of the total proved reserves in this area, 74% are liquid reserves and 26% gas reserves.

3.11.1 Development of reserves

In 2015, approximately 438 million boe were converted from undeveloped to developed proved reserves.

The start-up of production from Edvard Grieg, Oseberg Delta 2 and Valemon in Norway together with Bavuca and Kakocha in Angola and Corrib in Ireland increased the developed reserves by 69 million boe during 2015. The rest of the converted volume is related to development activities on producing fields.

Net proved reserves in million barrels oil equivalent	Total	Developed	Undeveloped
At 31 December 2014	5,359	3,725	1,635
Revisions and improved recovery	(42)	96	(138)
Extensions and discoveries	627	-	627
Purchase of reserves-in-place	13	6	7
Sales of reserves-in-place	(235)	(88)	(147)
Production	(662)	(662)	-
Moved from undeveloped to developed	-	438	(438)
At 31 December 2015	5,060	3,515	1,546

The new development projects in Norway, added a total of 476 million boe of proved undeveloped reserves in 2015, the largest being Johan Sverdrup. Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the US increased the proved area and added proved undeveloped reserves. These additions are categorised as extensions and together with extensions on existing fields and new discoveries this added a total of 627 million boe of proved undeveloped reserves.

Revision of estimate on existing fields added 96 million boe proved developed reserves and reduced proved undeveloped reserves by 138 million boe. These revisions are based on new information available either from drilling of new wells or from production experience, resulting in an improved understanding of the fields. The negative revisions are mainly linked to lower commodity prices resulting in earlier economic cut-off for the fields and undeveloped well locations becoming uneconomic.

The net effect of the transactions done in 2015, reduced the proved undeveloped reserves by 139 million boe.

		Oil and Condensate (mmboe)	NGL (mmboe)	Natural gas (bcf)	Total (mmboe)
2015	**Proved reserves end of year**	**2,091**	**364**	**14,624**	**5,060**
	Developed	1,104	290	11,901	3,515
	Undeveloped	987	74	2,723	1,546
2014	**Proved reserves end of year**	**1,942**	**403**	**16,919**	**5,359**
	Developed	1,156	310	12,677	3,725
	Undeveloped	786	93	4,242	1,635
2013	**Proved reserves end of year**	**1,877**	**441**	**18,416**	**5,600**
	Developed	1,052	330	13,073	3,711
	Undeveloped	826	111	5,343	1,888

As of 31 December 2015, the total proved undeveloped reserves amounted to 1,546 million boe, 76% of which are related to fields in Norway. The Troll, Snøhvit, Visund, Grane and Oseberg fields, which have continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Johan Sverdrup, Aasta Hansteen, Gina Krogh, Ivar Aasen and Goliat. The largest assets with respect to undeveloped proved reserves outside Norway are Bakken and Stampede in the US, Peregrino in Brazil, Hebron in Canada, Corrib in Ireland and In Salah in Algeria.

In 2015, Statoil incurred NOK 85 billion in development costs relating to assets carrying proved reserves, NOK 70 billion of which was related to proved undeveloped reserves.

Large fields with continuous development activity may contain reserves that are expected to remain undeveloped for five years or more. Examples are Johan Sverdrup, Troll, Snøhvit, Gina Krogh and Aasta Hansteen in Norway. These are large field developments with several billion dollars invested in complex infrastructure and with continuous development that will require extensive, sustained drilling of wells for a long period of time. It is highly unlikely that these field development projects will be prematurely terminated, since this would result in a significant loss of capital.

Additional information about proved oil and gas reserves is provided in note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

3.11.2 Preparations of reserves estimates

Statoil's annual reporting process for proved reserves is coordinated by a central team.

The corporate reserves management (CRM) team consists of qualified professionals in geosciences, reservoir and production technology and financial evaluation. The team has an average of more than 20 years' experience in the oil and gas industry. CRM reports to the senior vice president of finance and control in the Technology, Drilling and Projects business area and is thus independent of the Development & Production business areas in Norway, North America and International. All the reserves estimates have been prepared by Statoil's technical staff.

Although the CRM team reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and Statoil's corporate standards. Information about proved oil and gas reserves, standardised measures of discounted net cash flows related to proved oil and gas reserves and other information related to proved oil and gas reserves, is collected from the local asset teams and checked by CRM for consistency and conformity with applicable standards. The final numbers for each asset are quality-controlled and approved by the responsible asset manager, before aggregation to the required reporting level by CRM.

The aggregated results are submitted for approval to the relevant business area management teams and the corporate executive committee.

The person with primary responsibility for overseeing the preparation of the reserves estimates is the chair of the CRM team. The person who presently holds this position has a bachelor's degree in earth sciences from the University of Gothenburg, and a master's degree in petroleum exploration and exploitation from Chalmers University of Technology in Gothenburg, Sweden. She has 30 years' experience in the oil and gas industry, 29 of them with Statoil. She is a member of the Society of Petroleum Engineering (SPE) and vice-chair of the UNECE Expert Group on Resource Classification (EGRC).

DeGolyer and MacNaughton report

Petroleum engineering consultants DeGolyer and MacNaughton have carried out an independent evaluation of Statoil's proved reserves as of 31 December 2015. The evaluation accounts for 100% of Statoil's proved reserves. The aggregated net proved reserves estimates prepared by DeGolyer and MacNaughton do not differ materially from those prepared by Statoil when compared on the basis of net equivalent barrels.

Net proved reserves at 31 December 2015	Oil and Condensate (mmbbls)	NGL/LPG (mmbbl)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,091	364	14,624	5,060
Estimated by DeGolyer and MacNaughton	2,159	379	14,309	5,087

A reserves audit report summarising this evaluation is included as Exhibit 15 (a)(iv).

3.11.3 Operational statistics

Operational statistics include information about acreage and the number of wells drilled.

Developed and undeveloped acreage

The table below shows the total gross and net developed and undeveloped oil and gas acreage, in which Statoil had interests at 31 December 2015.

A gross value reflects wells or acreage in which Statoil has interests (presented as 100%). The net value corresponds to the sum of the fractional working interests owned in gross wells or acres.

At 31 December 2015 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	Americas	Oceania	Total
Developed and undeveloped oil and gas acreage							
Acreage developed	- gross	871	90	858	494	-	2,312
	- net	322	21	271	114	-	729
Acreage undeveloped	- gross	9,038	41,146	13,569	23,075	18,531	105,359
	- net	3,419	17,495	4,637	10,073	11,160	46,784

The largest concentrations of developed acreage in Norway are in the Troll, Skarv, Snøhvit, Ormen Lange and Oseberg areas. In Africa, the Algerian gas development projects In Amenas and In Salah represent the largest concentrations of developed acreage (gross and net).

Statoil's largest undeveloped acreage concentration is in Russia with 18% of the total acreage and 48% of the total acreage in Eurasia excluding Norway. In Russia, Statoil participates in a joint venture with Rosneft. The net acreage given in the table above represents Statoil's share of the joint venture. The largest concentration of undeveloped acreage in the Americas is Nicaragua, with 33% of the total for this geographic area. In Africa, the largest acreage concentration is in Angola, representing 56% of the total for this geographic area.

Statoil holds acreage in numerous concessions, blocks and leases. The terms and conditions regarding expiration dates vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration.

Acreage related to several of these concessions, blocks and leases are scheduled to expire within the next three years. Any acreage which has already been evaluated to be non-profitable may be relinquished prior to the current expiration date. In other cases, Statoil may decide to apply for an extension if more time is needed in order to fully evaluate the potential of the properties. Historically, Statoil has generally been successful in obtaining such extensions.

Most of the undeveloped acreage that will expire within the next three years is related to early exploration activities where no production is expected in the foreseeable future. The expiration of these leases, blocks and concessions will therefore not have any material impact on our reserves.

Productive oil and gas wells

The number of gross and net productive oil and gas wells, in which Statoil had interests at 31 December 2015, are shown in the table below.

At 31 December 2015		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells						
Oil wells	- gross	821	166	468	3,130	4,585
	- net	281.4	24.2	71.3	706.4	1,083.2
Gas wells	- gross	189	6	85	1,953	2,233
	- net	81.6	1.9	32.7	486.3	602.4

The total gross number of productive wells as of end 2015 includes 383 oil wells and 12 gas wells with multiple completions or wells with more than one branch.

Net productive and dry oil and gas wells drilled

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include exploratory wells in which hydrocarbons were discovered, and where drilling or completion has been suspended pending further evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Eurasia excluding Norway	Africa	Americas	Oceania	Total
Year 2015						
Net productive and dry exploratory wells drilled	10.2	1.0	2.5	2.6	-	16.3
- Net dry exploratory wells drilled	4.6	0.4	0.5	0.9	-	6.4
- Net productive exploratory wells drilled	5.6	0.7	2.0	1.7	-	9.9
Net productive and dry development wells drilled	32.1	4.1	10.6	228.8	-	275.6
- Net dry development wells drilled	3.6	-	4.3	0.3	-	8.2
- Net productive development wells drilled	28.6	4.1	6.3	228.5	-	267.4
Year 2014						
Net productive and dry exploratory wells drilled	12.0	1.0	4.7	3.4	3.6	24.7
- Net dry exploratory wells drilled	3.4	1.0	2.7	1.6	3.6	12.2
- Net productive exploratory wells drilled	8.6	-	2.0	1.9	-	12.5
Net productive and dry development wells drilled	26.9	2.7	8.5	386.1	-	424.2
- Net dry development wells drilled	3.5	-	1.1	1.2	-	5.8
- Net productive development wells drilled	23.4	2.7	7.4	384.9	-	418.4
Year 2013						
Net productive and dry exploratory wells drilled	19.3	0.3	2.2	2.3	-	24.0
- Net dry exploratory wells drilled	7.3	0.3	2.2	2.3	-	12.0
- Net productive exploratory wells drilled	12.0	-	-	-	-	12.0
Net productive and dry development wells drilled	26.7	2.3	5.9	321.9	-	356.7
- Net dry development wells drilled	1.7	-	0.7	1.3	-	3.7
- Net productive development wells drilled	24.9	2.3	5.3	320.6	-	353.1

Exploratory and development drilling in process
The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2015.

At 31 December 2015		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of wells in progress						
Development wells	- gross	68	4	13	202	287
	- net	24.5	0.3	2.7	67.7	95.2
Exploratory wells	- gross	1	-	-	8	9
	- net	0.4	-	-	5.4	5.8

3.11.4 Delivery commitments

This section describes the long-term NCS commitments for the contract gas years 2015-2018.

On behalf of the Norwegian State's direct financial interest (SDFI), Statoil is responsible for managing, transporting and selling the Norwegian state's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with Statoil's own reserves. As part of this arrangement, Statoil delivers gas to customers under various types of sales contracts. In order to meet the commitments, we utilise a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

The majority of our gas volumes in Norway are sold under long-term contracts with take-or-pay clauses. Statoil's and SDFI's annual delivery commitments under these agreements are expressed as the sum of the expected off-take under these contracts. As of 31 December 2015, the long-term commitments from NCS for the Statoil/SDFI arrangement totalled approximately 14.51 trillion cubic feet (tcf) (411 bcm).

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the gas years 2015, 2016, 2017 and 2018, are 2.28, 1.89, 1.56 and 1.22 tcf (64.7, 53.5, 44.2 and 44.0 bcm), respectively. The remaining volumes are sold to large industrial end users or on the short-term market.

Statoil's currently developed gas reserves in Norway are more than sufficient to meet our share of these commitments for the next three years.

3.12 Applicable laws and regulations

Statoil operates in more than 30 countries and is exposed to, and committed to compliance with, a number of laws and regulations globally.

This article focuses primarily on Norwegian laws, taking into account that the majority of Statoil's production is produced on the NCS, the ownership structure of the company and that Statoil is registered and has its headquarters in Norway.

3.12.1 Norwegian petroleum laws and licensing system

The principal laws governing Statoil's petroleum activities in Norway are the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

Norway is not a member of the European Union (EU), but Norway is a member of the European Free Trade Association (EFTA). The EU and the EFTA Member States have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, which provides for the inclusion of EU legislation covering the four freedoms - the free movement of goods, services, persons and capital - in the national law of the EFTA Member States (except Switzerland). An increasing volume of regulations affecting Statoil is adopted in the EU and then applied to Norway under the EEA Agreement. As a Norwegian company operating within both EFTA and the EU, Statoil's business activities are subject to both the EFTA Convention governing intra-EFTA trade and EU laws and regulations adopted pursuant to the EEA Agreement.

For further information about the jurisdictions in which Statoil operates, see sections 3 *Business overview and* 5 *Risk review.*

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy is responsible for resource management and for administering petroleum activities on the NCS. The main task of the Ministry of Petroleum and Energy is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Norwegian Parliament (the Storting) and relevant decisions of the Norwegian State.

The Storting's role in relation to major policy issues in the petroleum sector can affect Statoil in two ways: firstly, when the Norwegian State acts in its capacity as majority owner of Statoil shares and, secondly, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State's shareholding in Statoil is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally decide how the Norwegian State will vote on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if Statoil issues additional shares and such issuance would significantly dilute the Norwegian State's holding, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. A decision by the Norwegian State to vote against a proposal on Statoil's part to issue additional shares would prevent Statoil from raising additional capital in this manner and could adversely affect Statoil's ability to pursue business opportunities. For more information about the Norwegian State's ownership, see sections 5.1.3 *Risks related to state ownership* and 6.8 *Major shareholders*

- The Norwegian State exercises important regulatory powers over Statoil, as well as over other companies and corporations on the NCS. As part of its business, Statoil or the partnerships to which Statoil is a party, frequently need to apply for licences and other approval of various kinds from the Norwegian State. In respect of certain important applications, such as for the approval of major plans for the operation and development of fields, the Ministry of Petroleum and Energy must obtain the consent of the Storting before it can approve the relevant partnership's application. This may take additional time and affect the content of the decision. Although Statoil is majority-owned by the Norwegian State, it does not receive preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State

The principal laws governing Statoil's petroleum activities in Norway and on the NCS are the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act") and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorised to award licences for petroleum activities as well as determine its terms. Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy. Statoil is dependent on the Norwegian State for approval of its NCS exploration and development projects and its applications for production rates for individual fields.

Production licences are the most important type of licence awarded under the Petroleum Act and are normally awarded for an initial exploration period, which is typically six years, but which can be shorter. The maximum period is ten years. During this exploration period, the licensees must meet a specified work obligation set out in the licence. If the licensees fulfil the obligations set out in the initial license period, they are entitled to require that the licence be prolonged for a period specified at the time when the licence is awarded, typically 30 years.

However, the Ministry of Petroleum and Energy is not entitled to award Statoil a licence in an area until the Storting has decided to open the area in question for exploration. The terms of the production licences are decided by the Ministry of Petroleum and Energy. A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Production licences are awarded to group of companies forming a joint venture at the Ministry's discretion. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the licence. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the state's direct financial interest (SDFI) holds an interest, the Norwegian State, acting through Petoro AS, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence with respect to the Norwegian State's exploitation policies or financial interests. This power of veto has never been used.

Interests in production licences may be transferred directly or indirectly subject to the consent of the Ministry of Petroleum and Energy and the approval of the Ministry of Finance of a corresponding tax treatment position. In most licences, there are no pre-emption rights in favour of the other licensees. However, the SDFI, or the Norwegian State, as appropriate, still holds pre-emption rights in all licences.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement. A change of operator requires the consent of the Ministry of Petroleum and Energy. In special cases, the Ministry of Petroleum and Energy can order a change of operator.

Licensees are required to submit a plan for development and operation (PDO) to the Ministry of Petroleum and Energy for approval. For fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy.

If important public interests are at stake, the Norwegian State may instruct Statoil and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State instructed a reduction in oil production was in 2002.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. Ownership of most facilities for the transportation and utilisation of petroleum in Norway and on the NCS is organised in the form of joint ventures. The participants' agreements are similar to the joint operating agreements.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for the transportation and utilisation of petroleum expires or is relinquished, or the use of a facility ceases. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

For an overview of Statoil's activities and shares in Statoil's production licences on the NCS, see section 3.5 *Development and Production Norway (DPN).*

3.12.2 Gas sales and transportation from the NCS

Statoil markets gas from the NCS on its own behalf and on the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in the UK and mainland Europe.

Most of Statoil's and the Norwegian State's gas produced on the NCS is sold under gas contracts to customers in the European Union (EU). The EU internal energy market has been high on the European Commission's agenda, and this market has thus been subject to continuous legislative initiatives. Such changes in EU legislation may affect Statoil's marketing of gas.

The Norwegian gas transport system, consisting of the pipelines and terminals through which licensees on the NCS transport their gas, is owned by a joint venture called Gassled. The Norwegian Petroleum Act of 29 November 1996 and the pertaining Petroleum Regulation establish the basis for non-discriminatory third-party access to the Gassled transport system. The ownership structure in Gassled and the pertaining regulations are intended to ensure the effectiveness of the system and to prevent conflicts of interest.

To ensure neutrality, the petroleum regulations also stipulate that all booking and allocation of capacity is administrated by Gassco AS, an independent system operator wholly owned by the Norwegian State. Spare capacity is released and allocated to shippers by Gassco based on standard procedures. Capacity that has already been allocated to a shipper may also be transferred bilaterally between shippers.

The tariffs for the use of capacity in the transport system are determined by applying a formula set out in separate tariff regulations stipulated by the Ministry of Petroleum and Energy. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported. The Ministry's main objective when setting the tariffs is to ensure that the profits are extracted in the production fields on the NCS and not in the transport system.

For further information see section 3.7.3.3 *Pipelines*.

3.12.3 The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

Initially, the Norwegian State's participation in petroleum operations was largely organised through Statoil. In 1985, the Norwegian State established the State's direct financial interest (SDFI) through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which Statoil also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

3.12.4 SDFI oil and gas marketing and sale

Statoil markets and sells the Norwegian State's oil and gas together with Statoil's own production. The arrangement has been implemented by the Norwegian State.

At an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised Statoil's articles of association by adding a new article that requires Statoil to continue to market and sell the Norwegian State's oil and gas together with its own oil and gas. At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved an instruction to Statoil setting out specific terms for the marketing and sale of the Norwegian State's oil and gas. This resolution is referred to as the Owner's instruction.

The Norwegian State has a coordinated ownership strategy aimed at maximising the aggregate value of its ownership interests in Statoil and the Norwegian State's oil and gas. This is reflected in the Owner's instruction. It contains a general requirement that, in Statoil's activities on the NCS, it must take account of these ownership interests in decisions that could affect the execution of this marketing arrangement.

The principal provisions of the Owner's instruction are set out below.

Objectives
The overall objective of the marketing arrangement is to obtain the highest possible total value for Statoil's oil and gas and the Norwegian State's oil and gas, and to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil.

Statoil's tasks
Statoil's main tasks under the Owner's instruction are to market and sell the Norwegian State's oil and gas and to carry out all the necessary related activities, other than those carried out jointly with other licensees under production licences. This includes, but is not limited to, responsibility for processing, transport and marketing.

Costs
The Norwegian State does not pay Statoil a specific consideration for performing these tasks, but reimburses its proportionate share of certain costs, which, under the Owner's instruction, may be Statoil's actual costs or an amount specifically agreed.

Price mechanisms
Payment to the Norwegian State for sales of the Norwegian State's natural gas, both to Statoil and to third parties, is based either on the prices achieved, a net back formula or market value. Statoil purchases all of the Norwegian State's oil and NGL. Pricing of the crude oil is based on market-reflective prices. NGL prices are based on either achieved prices, market value or market-reflective prices.

Lifting mechanism
To ensure neutral weighting between the Norwegian State's and Statoil's own natural gas volumes, a list has been established for deciding the lifting priority between each individual field. The different fields are ranked in accordance with their assumed total value creation for the Norwegian State and Statoil, assuming that all of the fields meet our profitability requirements if we participate as a licensee and the Norwegian State's profitability requirements if the State is a licensee. Within each individual field in which both the Norwegian State and Statoil are licensees, the Norwegian State and Statoil will deliver volumes and share income in proportion to our respective participating interests.

The Norwegian State's oil and NGL is lifted together with our oil and NGL in accordance with applicable lifting procedures for each individual field and terminal.

Withdrawal or amendment
The Norwegian State may at any time utilise its position as majority shareholder of Statoil to withdraw or amend the owner's instruction.

3.12.5 HSE regulation

Statoil's petroleum operations are subject to extensive laws and regulations relating to health, safety and the environment (HSE).

With business operations in more than 30 countries, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. Laws and regulations may be jurisdiction specific, but also international regulations, conventions or treaties, as well as EU directives and regulations, are relevant.

In Norway, under the Norwegian Petroleum Act of 29 November 1996, Statoil's oil and gas operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in step with technological developments. Statoil is also required at all times to have a plan to deal with emergency situations in our petroleum operations. During an emergency, the Norwegian Ministry of Labour/Norwegian Ministry of Fisheries and Coastal Affairs/Norwegian Coastal Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the licensees' account.

As a result of the Macondo incident, in 2011, the US Department of the Interior created two new agencies to administer operations and activities in the Gulf of Mexico - the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Offshore Energy Management (BOEM). The department also issued new regulations to address the respective roles of the new agencies. Application of these regulations has the potential to affect Statoil's operations in the US. Similarly, the effects from implementing the EU offshore Safety Directive in EU-member states' legislation will affect operations in relevant EU member countries.

See also section 5.1 *Risk factors*.

3.12.6 Taxation of Statoil

Statoil is subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to its offshore activities in Norway. Internationally, Statoil's activities are mainly subject to tax in the countries where it operates.

Taxation in Norway
Statoil's Norwegian petroleum activities are subject to ordinary corporate income tax and to a special petroleum tax. In addition, there are taxes on both carbon dioxide emissions and emissions of nitrogen oxide (NOx).

Corporate income tax
Statoil's profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The standard corporate income tax rate has been reduced from 27% in 2015 to 25% in 2016. Statoil's profits are computed in accordance with ordinary Norwegian corporate income tax rules, subject to certain modifications that apply to companies engaged in petroleum operations. Gross revenue from oil production is determined on the basis of norm prices. Norm prices are decided on a daily basis by the Petroleum Price Board, and published quarterly. The Petroleum Tax Act states that the norm prices shall correspond to the prices that could have been obtained in a sale of petroleum between independent parties in a free market.

The maximum rate of depreciation of development costs relating to offshore production installations and pipelines is 16.67% per year. Depreciation starts when the cost is incurred. Exploration costs may be deducted in the year in which they are incurred. Financial costs related to the offshore activity are calculated directly based on a formula set out in the Petroleum Tax Act. The financial costs deductible under the offshore tax regime are the total interest costs and exchange gains and losses related to interest-bearing debt multiplied by 50% of the tax values covered by the petroleum tax regime divided by the average interest-bearing debt. All other financial costs and income are allocated to the onshore tax regime.

Abandonment costs incurred can be deducted as operating expenses. Provisions for future abandonment costs are not tax deductible.

Any tax losses can be carried forward indefinitely against subsequent income earned. 50% of losses relating to activity conducted onshore in Norway can be deducted from NCS income subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016). Losses on foreign activities cannot be deducted from NCS income.

By using group contributions between Norwegian companies in which Statoil holds more than 90% of the shares and votes, tax losses and taxable income can be offset to a great extent. Group distributions are not deductible from Statoil's NCS income.

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016). Dividends received from Norwegian companies and from similar companies resident in the EEA for tax purposes, in which the recipient holds more than 90% of the shares and votes, are fully exempt from tax. Dividends from companies resident in the EEA that are not similar to Norwegian companies, companies in low-tax countries and portfolio investments outside the EEA will, under certain circumstances, be subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) based on the full amounts received.

Capital gains from the realisation of shares are exempt from tax. Exceptions apply to shares held in companies resident in low-tax countries or portfolio investments in companies resident outside the EEA for tax purposes, where, under certain circumstances, capital gains will be subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) and capital losses will be deductible.

Special petroleum tax
A special petroleum tax is levied on profits from petroleum production and pipeline transportation on the NCS. The special petroleum tax rate has been increased from 51% in 2015 to 53% in 2016. The special petroleum tax rate is applied to relevant income in addition to the standard income tax rate, resulting in a 78% marginal tax rate on income subject to the special petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible from the special petroleum tax basis, and a tax-free allowance, or uplift, is granted at a rate of 5.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift can be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift can be carried forward indefinitely. For further information see note 9 *Income taxes*.

Taxation outside Norway
Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of Statoil's upstream operations is generally based on corporate income tax regimes and/or production sharing agreements (PSA). Royalties may apply in either case. Statoil is subject to excess (or "windfall") profit tax in some of the countries in which it produces crude oil or condensate.

Production sharing agreements (PSA)
Under a PSA, the host government typically retains the right to the hydrocarbons in place. The contractor normally receives a share of the oil produced to recover its costs, and is also entitled to an agreed share of the oil as profit ("profit oil"). The state's share of profit oil typically increases based on a success factor, such as surpassing certain specified internal rates of return, production rates or accumulated production. The contractor is usually subject to income tax on its own share of the profit oil. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery and are then entitled to recover those costs during the production phase. Fiscal provisions in a PSA are to a large extent negotiable and are unique to each PSA.

Income tax regimes
Under an income tax/royalty regime, companies are granted licences by the government to extract petroleum, and the state may be entitled to royalties, which are generally assessed on gross revenue from production, and a profit tax, which is generally based on the company's net taxable income from production as defined in a country's domestic tax legislation. In some countries, income from petroleum activities is also subject to a special petroleum tax in addition to ordinary corporate tax. In general, the fiscal terms surrounding these licences are non-negotiable and the company is subject to legislative changes in the tax laws.

3.13 Property, plant and equipment

Statoil has interests in real estate in many countries throughout the world. However, no individual property is significant.

Statoil's head office is located at Forusbeen 50, NO-4035, Stavanger, Norway and comprises approximately 135,000 square metres of office space. In June 2015 Statoil closed a sales transaction for the sale of the company's head office building in Stavanger, and at the same time, Statoil entered into a 15 year operating lease agreement for the building. For more information see note 4 *Acquisitions and disposals* to the Consolidated financial statements.

In October 2012, Statoil moved into a new 65,500-square-metre office building located at Fornebu on the outskirts of Norway's capital Oslo. Statoil as tenant has signed a long-term lease agreement with the owner of the office building, IT-Fornebu AS. The new office building provides an environmentally friendly workplace for up to 2,500 employees.

For a description of our significant reserves and sources of oil and natural gas, see note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

3.14 Related party transactions

See note 24 *Related parties* to the Consolidated financial statements for information concerning related parties.

3.15 Insurance

Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage.

Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Our well control policies, which cover costs relating to well control incidents (including pollution and clean-up costs) are subject to the following limits for the two of the areas Statoil operates:

NCS
- NOK 2,500 million plus USD 1,500 million per incident for exploration wells
- NOK 2,000 million per incident for production wells

Gulf of Mexico
- Local well control limit (typically in the area of USD 300 million) plus USD 1,500 million per incident for exploration wells
- Local well control limit (typically in the area of USD 300 million) for production wells

The above limits assume a 100% ownership interest in a given well and would scaled to be equivalent to our percentage ownership interest in a given well. In addition to the well control insurance programmes, we have in place a third-party liability insurance programme with a gross limit of USD 800 million per incident.

3.16 People and the group

3.16.1 Employees in Statoil

The Statoil group employs approximately 21,600 employees. Of these, approximately 19,000 are employed in Norway and approximately 2,600 outside Norway.

Permanent employees and percentage of women in the Statoil group	Number of employees 2015	2014	2013	Women 2015	2014	2013
Norway	18,977	19,670	20,336	30%	30%	30%
Rest of Europe	855	909	935	29%	31%	30%
Africa	98	117	140	35%	34%	33%
Asia	97	135	140	36%	52%	53%
North America	1,265	1,375	1,559	35%	34%	35%
South America	289	310	303	38%	40%	38%
TOTAL	21,581	22,516	23,413	30%	31%	31%
Non-OECD	590	677	690	40%	40%	39%

Total workforce by region, employment type and new hires in the Statoil group in 2015

Geographical Region	Permanent employees	Consultants	Total Workforce[1)]	Consultants (%)	Part time (%)	New hires
Norway	18,977	424	19,401	2%	3%	103
Rest of Europe	855	99	954	10%	1%	70
Africa	98	5	103	5%	NA	6
Asia	97	5	102	5%	NA	2
North America	1,265	112	1,377	8%	0%	142
South America	289	3	292	1%	0%	8
TOTAL	21,581	648	22,229	3%	3%	331
Non-OECD	590	15	605	2%	na	19

1) Enterprise personnel, defined as third-party service providers who work at our onshore and offshore operations, are not included. These were roughly estimated to be around 30,500 in 2015.

Statoil works systematically with recruitment and development programmes in order to build a diverse workforce by attracting, recruiting and retaining people of both genders and different nationalities and age groups across all types of positions.

In 2015, 19% of employees and 22% of our managerial staff held nationalities other than Norwegian. Outside Norway, Statoil aims to increase the number of people and managers who are locally recruited and to reduce the long-term use of expats in business operations. In 2015, 73% of new hires in Statoil were non-Norwegians and 35% were women.

In Statoil, the total turnover rate for 2015 was 3.6%. On 31 December 2015, the Statoil group employed 21.581 permanent employees and 3% of the workforce worked part-time. In the annual organisational and working environment survey, which continued to have a high response of 85%, our employees reported an overall satisfaction of 4.6. This is a slight increase from the score of 4.5 in 2014.

Our people performance data relates to permanent employees in our direct employment. Statoil defines consultants as contracted personnel that are mainly based in our offices. Temporary employees and enterprise personnel are not included in the workforce table. Enterprise personnel are defined as third party service providers and work on our on-shore and off-shore operations. These were roughly estimated to be around 30,500 in 2015. The information about people policies applies to Statoil ASA and its subsidiaries.

3.16.2 Equal opportunities

We are committed to building a workplace that promotes diversity and inclusion through its people processes and practices.

We promote diversity among our employees. We try to create the same opportunities for everyone and do not tolerate discrimination or harassment of any kind in our workplace. In 2015, we continued to focus on strengthening women in leadership and professional positions and on building broad international experience in our workforce. Our commitment to diversity and inclusion was demonstrated in the 2015 Global People Survey, where we maintained our high score of 5.1 (6 being the highest) for the existence of zero tolerance for discrimination and harassment within the workplace.

In 2015, the overall percentage of women in the company was 30%. The percentage of women in the board of directors is 50% (67% among the employee representatives and 43% among members elected by the shareholders). In the corporate executive committee the female representation has increased from last year's 11% to 18% in 2015. We pay close attention to male-dominated positions and discipline areas, and in 2015 the proportion of female engineers remained stable at 27% in Statoil ASA. Among staff engineers with up to 20 years' experience, the proportion of women increased to 31%. We continue to strive to increase the number of female managers through our development programmes, and in 2015 despite the overall reduction of 181 leadership positions, we increased the share of women in management by 0.5%. The percentage of appointment of women in new leadership positions in 2015 was 36%.

At Statoil we reward our people on the basis of their performance, giving equal emphasis to delivery and behaviour. Our reward approach is adapted to local market conditions at the locations in which we operate and is transparent, non-discriminatory and supports equal opportunities. Given the same position, experience and performance, our employees will be at the same remuneration level relative to the local market. This is demonstrated in the salary ratio between women and men at different levels in Statoil ASA. In 2015 we have maintained a high ratio, with an average of 98%.

The intake of apprentices in Norway is an important part of the company's recruitment of skilled workers and commitment to the education and training of young technicians and operators in the oil and gas industry. In 2015, apprenticeships were given to 130 new students; of these 42 were female. The total number of apprentices in Statoil is 282.

3.16.3 Unions and representatives

Statoil's cooperation with employee representatives and trade unions is based on confidence, trust and continuous dialogue between management and the people in various cooperative bodies.

In Statoil ASA, 70% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement. Town hall meetings are also used for information and consultations in accordance with requirements and usage in each country.

In Norway, the formal basis for collaboration with labour unions is established in the Basic Agreements between the Confederation of Norwegian Enterprise (NHO) and the corresponding respective national labour confederations (unions).

Statoil promotes good employee and industrial relations practices through various networks and forums, including IndustriALL Global Union (IndustriAll) and International Labour Organisation (ILO).

In 2015, management and employee representatives collaborated closely, in particular on the three corporate change initiatives Statoil technical efficiency programme (STEP), Organisational efficiency programme (OE) and Corporate Review 2015. In addition, the European Works Council continued to be an important channel between the company and employees.

We collaborate with employee representatives in the change processes, and we strive to find solutions that are satisfactory both for our employees and for the company. To handle redundancies resulting from the ongoing change processes in 2015, we used measures such as internal deployment, severance packages and early retirement.

3.17 Safety, security and sustainability

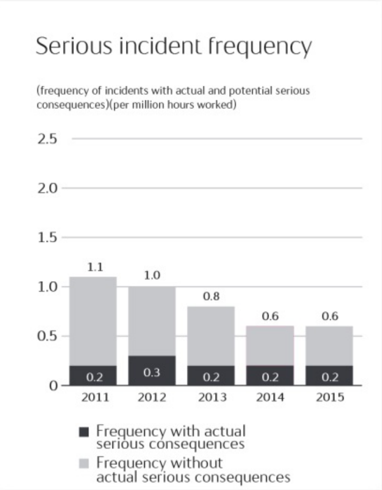
Statoil's ambition is to be an industry leader in safety, security and carbon efficiency.

Safety and security

Statoil's ambition is to ensure safe and secure operations that protect people, the environment, communities and assets. Statoil's approach to safety and security entails preventing accidents and incidents, avoiding oil spills, ensuring a healthy work environment and developing a strong security culture.

Statoil works closely with industry peers on incident prevention and emergency preparedness. Through assurance activities, and by analysing Statoil's own incidents along with those of the industry at large, Statoil aims to ensure a dynamic approach to safety and security performance management. A global oil spill response system has been established, which includes close collaboration with industry peers and national and local communities. Trained response teams and sufficient equipment are ready to be mobilised when and where needed.

Everyone working for Statoil, and in the joint ventures controlled by Statoil, is required to comply with Statoil's safety, health and security standards. Statoil actively engages with contractors and joint ventures to encourage the embedding of a strong safety and security culture in the workforce.



Statoil uses serious incident frequency (SIF) as a key indicator to monitor safety performance. This indicator (number of serious incidents, including near misses, per million hours worked) combines actual consequences of incidents and the potential for incidents to develop into serious or major accidents. The SIF has significantly improved over the last years, from 1.1 incidents per million hours worked in 2011 to 0.6 incidents per million hours worked in 2015.

Total recordable injuries per million hours worked (TRIF) improved from 3.0 in 2014 to 2.7 in 2015. The TRIF for Statoil's employees was 2.3 and the TRIF for Statoil's contractors was 2.8.

Regrettably, there were three fatalities related to Statoil's operations in 2015. One person died and two persons were injured as a result of a breaking wave that hit the drilling rig COSL Innovator on 30 December 2015. Two separate road accidents in the USA resulted in two fatalities.

Accidental oil spills were significantly reduced from 2014 to 2015. The total volume spilt was 23 m^3 in 2015, down from 125 m^3 in 2014.

Preventing oil and gas leakages is important to avoid major accidents. In 2015, the total number of serious leakages (leakages above 0.1kg/sec) increased to 21, up from 13 in 2014. All leakages are undergoing formal investigations and in-depth studies in order to capture learning and prevent similar incidents in the future.

Security is a key issue for the oil and gas industry because it operates in many unstable regions. At Statoil, security risk is systematically assessed on a continuous basis in order to achieve effective and proportionate security risk management. No security incidents with major consequences for Statoil were recorded in 2015. The two-year Security Improvement Programme, established to significantly raise security capabilities and develop a stronger security culture, was finished on schedule in 2015. A road map has been established to further strengthen our security culture and capabilities by 2020.

Climate change

Statoil recognises the ambition to limit the average global temperature rise to below two degrees centigrade compared to pre-industrial levels. The Paris agreement on climate change negotiated at the UN Conference of Parties (COP21) in December 2015 provides the prospect of improved policy support around the world for accelerating the shift to low carbon solutions. Statoil welcomes the agreement and believes that the company is well positioned to play its part.

Statoil's approach to climate change entails four key aspects:

- supporting the development of viable global climate policies
- managing climate risks and opportunities
- managing emissions
- developing low carbon energy solutions

Statoil carefully monitors and assesses the potential impact of climate change. Both the corporate executive committee and board of directors frequently discuss the business risks and opportunities associated with climate change, including market, regulatory and physical risk factors. Tools such as internal carbon pricing, scenario planning and stress testing of projects against various oil and gas price assumptions, are used. Statoil regularly assesses how the development of technologies and changes in regulations, including the introduction of stringent climate policies, may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.

Statoil's efforts to reduce direct greenhouse gas (GHG) emissions includes improving energy efficiency; reducing methane emissions; eliminating routine flaring and scaling up carbon capture and storage.

The production from Statoil-operated assets increased from 997 mmboe in 2014 to 1073 mmboe in 2015[1]. The total direct GHG emissions from Statoil's operated assets remained stable at 16.3 million tonnes CO_2 equivalents in 2015. GHG emissions include carbon dioxide (CO_2) and methane (CH_4), where CO_2 constitutes the largest part (15.4 million tonnes in 2015).

In 2015, Statoil established a 2020 carbon intensity target of 9 kg CO_2/boe for its upstream activities. Statoil's upstream carbon intensity was 10kg CO_2/boe in 2015 - less than 60% of the industry average of 18kg as measured by the International Association of Oil and Gas Producers (Environmental Performance Indicators, 2014 data).

Indirect (scope 2) GHG emissions were 0.3 million tonnes CO_2 equivalents in 2015, using a location based emission factor. Scope 3 GHG emissions (emissions from the use of Statoil's equity production) were estimated to 295 million tonnes CO_2 equivalents.

Statoil's operations in Europe are subject to emissions allowances according to the EU Emissions Trading System (EU ETS). Statoil's Norwegian operations are subject to both the Norwegian offshore CO_2 tax and EU ETS quotas. In 2015, Statoil paid some NOK 4.0 billion in CO_2 tax and quotas.

In 2015, Statoil announced a new business area for New Energy Solutions. Statoil's approach to growth opportunities within renewables and new energy solutions includes both commercial investments and research and development (R&D). Statoil has made investments in offshore wind projects and continues to be engaged in carbon capture and storage. A significant proportion of Statoil's R&D efforts address energy efficiency, carbon capture and renewables. See section 3.8.1 *New Energy Solutions (NES)* for more information.

Environmental impact and resource efficiency

Statoil is committed to using resources efficiently and strives to apply high standards for waste management, emissions to air and impact on ecosystems - in all operations. Statoil's fresh water consumption decreased from 14.8 million cubic metres in 2014 to 14.5 million cubic metres in 2015. Improving water efficiency in the onshore activities in North America through means such as water recycling and substituting fresh water with brackish water, is a priority.

Working with suppliers

Statoil is committed to using suppliers who operate consistently in accordance with Statoil's values and who maintain high standards of safety, security and sustainability. These aspects are incorporated in all phases of the procurement process. All potential suppliers must meet Statoil's minimum requirements in order to qualify as a supplier and these include safety, security and sustainability criteria.

After awarding a contract, a supplier follow-up strategy is established, based on a risk assessment. Statoil's expectations regarding safety, security and sustainability are communicated to the supplier in the contract start-up meeting and throughout the contract period. Assurance activities are conducted, such as follow-up meetings, verifications and audits to manage identified risks. Supply chain personnel are trained in safety, security and sustainability risk handling through classroom courses, e-learning courses and awareness sessions.

Human rights

Statoil seeks to conduct its business in a way that is consistent with the ten UN Guiding Principles on Business and Human Rights (the UN Guiding Principles), the UN Global Compact principles and the Voluntary Principles on Security and Human Rights. Statoil is committed to respecting internationally recognised human rights as laid out in the International Bill of Human Rights, the International Labour Organisation's 1998 Declaration on Fundamental Rights and Principles at Work, and applicable standards of international humanitarian law.

Throughout 2015, a stand-alone human rights policy was developed, to give greater weight to Statoil's long-standing commitment to respect human rights. The policy was based on consultations and workshops with relevant experts and stakeholders. A gap analysis has been initiated to identify how Statoil's human rights processes and practices need to further evolve to reflect the new policy. Human rights aspects are integrated into relevant internal management processes, tools and training. On-going activities, business relationships and new business opportunities are assessed for potential human rights impacts and aspects, following a risk-based approach. In 2015, supplier verification practices were enhanced. Human rights training is provided to employees based on risk and relevance.

[1] Climate and environmental performance data represent total figures from Statoil-operated assets (operational control), except from scope 3 emissions, which are calculated based on Statoil's equity production.

4 Financial review

4.1 Operating and financial review

4.1.1 Sales volumes

Sales volumes include lifted entitlement volumes, the sale of SDFI volumes and marketing of third-party volumes.

In addition to Statoil's own volumes, we market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licences. This is known as the State's Direct Financial Interest or SDFI. For additional information, see section 3.12.4 *SDFI oil and gas marketing and sale*. The following table shows the SDFI and Statoil sales volume information on crude oil and natural gas for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by the MMP segment, natural gas volumes sold by the DPI segment and ethane volumes.

	For the year ended 31 December		
Sales Volumes 1)	2015	2014	2013
Statoil: 2)			
Crude oil (mmbbls) 3)	**378**	353	347
Natural gas (bcf)	**1,645**	1,596	1,622
Combined oil and gas (mmboe)	**671**	637	636
Third party volumes: 4)			
Crude oil (mmbbls) 3)	**290**	304	303
Natural gas (bcf)	**304**	285	434
Combined oil and gas (mmboe)	**344**	355	380
SDFI assets owned by the Norwegian State: 5)			
Crude oil (mmbbls) 3)	**149**	148	155
Natural gas (bcf) 1)	**1,400**	1,254	1,351
Combined oil and gas (mmboe)	**398**	371	396
Total:			
Crude oil (mmbbls) 3)	**816**	805	805
Natural gas (bcf)	**3,348**	3,134	3,407
Combined oil and gas (mmboe)	**1,413**	1,363	1,412

1) The volumes in columns 2014 and 2013 are updated to reflect total sales volumes of crude oil (mmbbls) and natural gas (bcf). Previously only volumes from MMP were disclosed.

2) The Statoil volumes included in the table above are based on the assumption that volumes sold were equal to lifted volumes in the relevant year. Volumes lifted by DPI but not sold by MMP, and volumes lifted by DPN or DPI and still in inventory or in transit may cause these volumes to differ from the sales volumes reported elsewhere in this report by MMP.

3) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.

4) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the US.

5) The line item SDFI assets owned by the Norwegian State include sales of both equity production and third party gas.

4.1.2 Group profit and loss analysis

Net operating income was down by 86% in 2015, impacted by significantly lower prices and increased net impairment losses.

Operational data	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Prices					
Average Brent oil price (USD/bbl)	**55.3**	98.9	108.7	(44%)	(9%)
Development and Production Norway average liquids price (USD/bbl)	**48.2**	90.6	101.0	(47%)	(10%)
Development and Production International average liquids price (USD/bbl)	**42.9**	85.6	98.4	(50%)	(13%)
Group average liquids price (USD/bbl)	**45.9**	88.6	100.0	(48%)	(11%)
Group average liquids price (NOK/bbl) [1]	**370.7**	558.5	587.8	(34%)	(5%)
Transfer price natural gas (NOK/scm) [9]	**1.58**	1.57	1.92	1%	(18%)
Average invoiced gas prices - Europe (NOK/scm) [8]	**2.16**	2.28	2.45	(5%)	(7%)
Average invoiced gas prices - North America (NOK/scm) [8]	**0.79**	1.04	0.83	(24%)	25%
Refining reference margin (USD/bbl) [2]	**8.0**	4.7	4.1	70%	15%
Entitlement production (mboe per day)					
Development and Production Norway entitlement liquids production	**595**	588	591	1%	(1%)
Development and Production International entitlement liquids production	**436**	383	354	14%	8%
Group entitlement liquids production	**1,032**	971	945	6%	3%
Development and Production Norway entitlement gas production	**637**	595	626	7%	(5%)
Development and Production International entitlement gas production	**144**	163	148	(12%)	10%
Group entitlement gas production	**781**	758	773	3%	(2%)
Total entitlement liquids and gas production [3]	**1,812**	1,729	1,719	5%	1%
Equity production (mboe per day)					
Development and Production Norway equity liquids production	**595**	588	591	1%	(1%)
Development and Production International equity liquids production	**569**	538	524	6%	3%
Group equity liquids production	**1,165**	1,127	1,115	3%	1%
Development and Production Norway equity gas production	**637**	595	626	7%	(5%)
Development and Production International equity gas production	**170**	205	200	(17%)	3%
Group equity gas production	**806**	801	825	1%	(3%)
Total equity liquids and gas production [4]	**1,971**	1,927	1,940	2%	(1%)
Liftings (mboe per day)					
Liquids liftings	**1035**	**967**	**950**	7%	2%
Gas liftings	**802**	**779**	**792**	3%	(2%)
Total liquids and gas liftings	**1837**	**1,746**	**1,742**	5%	0%
Marketing, Midstream and Processing sales volumes					
Crude oil sales volumes (mmbl)	**829**	811	809	2%	0%
Natural gas sales Statoil entitlement (bcm)	**44.0**	43.1	44.3	2%	(3%)
Natural gas sales third-party volumes (bcm)	**8.6**	8.1	12.3	6%	(34%)
Production cost (NOK/boe, last 12 months)					
Production cost entitlement volumes	**52**	55	50	(5%)	10%
Production cost equity volumes	**48**	49	44	(2%)	11%

Total equity liquids and gas production (see section 9 *Terms and definitions)* was 1,971 mboe, 1,927 mboe and 1,940 mboe per day in 2015, 2014 and 2013, respectively.

The 2% increase in total equity production from 2014 to 2015 was primarily due to start-up and ramp-up on various fields, higher gas sales from the NCS and improved operational performance. Expected natural decline and reduced ownership shares as a result of divestments and redeterminations partially offset the increase.

The total equity production in 2014 was slightly lower compared to 2013. Start-up and ramp-up of production on various fields and higher production regularity compared to last year were offset by expected natural decline and reduced ownership shares from divestments.

Total entitlement liquids and gas production was 1,812 mboe per day in 2015 compared to 1,729 mboe in 2014 and 1,719 mboe per day in 2013.

The total entitlement production in 2015 was up 5% for the same reasons as described above. The benefit of lower effect from production sharing agreements (PSA effect) mainly driven by the reduction in prices, added to the increase in entitlement production. From 2013 to 2014 the development in total entitlement production was almost flat for the same reasons as described above and the benefit from lower PSA-effects.

The PSA effect was 116 mboe, 157 mboe and 182 mboe per day in 2015, 2014 and 2013, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period, see section 9 *Terms and definitions* for more information.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014 (restated)	2013 (restated)	15-14 change	14-13 change
Revenues	**465.3**	606.8	616.6	(23%)	(2%)
Net income from equity accounted investments	**(0.3)**	(0.3)	0.1	2%	>(100%)
Other income	**17.8**	16.1	17.8	11%	(10%)
Total revenues and other income	**482.8**	622.7	634.5	(22%)	(2%)
Purchases [net of inventory variation]	**(211.2)**	(301.3)	(306.9)	(30%)	(2%)
Operating expenses and selling, general and administrative expenses	**(91.9)**	(80.2)	(81.9)	15%	(2%)
Depreciation, amortisation and net impairment losses	**(133.8)**	(101.4)	(72.4)	32%	40%
Exploration expenses	**(31.0)**	(30.3)	(18.0)	2%	69%
Net operating income	**14.9**	109.5	155.5	(86%)	(30%)
Net financial items	**(10.6)**	(0.0)	(17.0)	>100%	(100%)
Income before tax	**4.3**	109.4	138.4	(96%)	(21%)
Income tax	**(41.6)**	(87.4)	(99.2)	(52%)	(12%)
Net income	**(37.3)**	22.0	39.2	>(100%)	(44%)

Total revenues and other income amounted to NOK 482.8 billion in 2015 compared to NOK 622.7 billion in 2014 and NOK 634.5 billion in 2013. Revenues are generated from both the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil, and from the sale of liquids and gas purchased from third parties. In addition, we market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as Purchases [net of inventory variations] and Revenues, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net.

The 23% decrease in **revenues** from 2014 to 2015 was mainly due to the significant reduction in both liquids and gas prices measured in NOK. Stronger refinery margins in 2015 and higher volumes of both liquids and gas sold partially offset the decrease.

The 2% decrease in revenues from 2013 to 2014 was mainly due to decreased prices for liquids and European gas and reduced volumes of liquids and gas sold, partly offset increased US gas prices and the exchange rate development (USD/NOK). Also, revenues in 2014 were positively impacted by gains from derivatives, mainly due to a significant drop in the forward curve in the oil market.

Other income was NOK 17.8 billion in 2015 compared to NOK 16.1 billion in 2014 and NOK 17.8 billion in 2013. Other income in 2015 was mainly related to gains from sales of certain ownership interest the Shah Deniz project (NOK 12.4 billion), the Trans Adriatic Pipeline (NOK 1.4 billion) and the Gudrun field (NOK 1.2 billion). Also, gain from sales of office buildings in Norway (NOK 2.1 billion) impacted other income in 2015.

Other income in 2014 consisted of the gain from the sale of certain ownership interests on the NCS to Wintershall (NOK 5.9 billion) and the divestment of working interests in the Shah Deniz Project and South Caucasus Pipeline (NOK 5.4 billion.) In addition, an arbitration settlement (NOK 2.8 billion) following an arbitration ruling in Statoil's favour, impacted other income in 2014. In 2013, other income consisted of gains from sale of certain ownership interests on the NCS to OMV (NOK 10.1 billion) and Wintershall (NOK 6.4 billion).

As a result of the factors explained above, **total revenue and other income** decreased by 22% in 2015. In 2014, the decrease was 2%.

Purchases [net of inventory variation] include the cost of liquids purchased from the Norwegian State, which is pursuant to the Owner's instruction, and the cost of liquids and gas purchased from third parties. See section 3.12.4 *SDFI oil and gas marketing and sale* for more details.

Purchases [net of inventory variation] amounted to NOK 211.2 billion in 2015 compared to 301.3 billion in 2014 and NOK 306.9 billion in 2013. The 30% decrease from 2014 to 2015 was mainly related to the significant lower prices for liquids and gas and other oil products and a write-down of inventories from cost to market value of NOK 3.9 billion, partially offset by the USD/NOK exchange rate development. The 2% decrease from 2013 to 2014 was mainly related to lower prices for liquids and gas including the write-down of inventories from cost-to-market value of NOK 4.0 billion and reduced third-party volumes. These effects were partially offset by the USD/NOK exchange rate development.

Operating expenses and selling, general and administrative expenses amounted to NOK 91.9 billion in 2015 compared to NOK 80.2 billion in 2014, and NOK 81.9 billion in 2013.

The 15% increase from 2014 to 2015 was mainly due to the USD/NOK exchange rate development in 2015 and because a curtailment gain related to the change of pension plan was included in 2014 (discussed below). Lower operation and maintenance costs, lower royalties due to reduced liquids prices, lower transportation costs and portfolio changes in addition to positive effects from on-going cost initiatives, partially offset the increase. Excluding the USD/NOK exchange rate development and the effect of the curtailment gain in 2014, operating expenses and selling, general and administrative expenses decreased by 3%.

The 2% decrease from 2013 to 2014 was mainly due to a curtailment gain of NOK 3.5 billion recognised upon the decision to change the company's pension plan in Norway in 2014 and an onerous contract provision of NOK 4.9 billion related to the Cove Point terminal in the US recognised in 2013. These effects were offset by increased expenses in 2014 mainly due to new fields coming on stream, onshore production ramp-up and increased transportation costs in the North America. In addition, the exchange rate development (NOK/USD) increased the expenses in 2014 compared to 2013.

Depreciation, amortisation and net impairment losses amounted to NOK 133.8 billion in 2015 compared to NOK 101.4 billion in 2014 and NOK 72.4 billion in 2013. Included in these totals were net impairment losses of NOK 47.8 billion, NOK 26.9 billion and NOK 7.0 billion for 2015, 2014 and 2013 respectively, related to the continuously falling commodity prices.

Net impairment losses of NOK 47.8 billion in 2015 were mainly related to unconventional onshore assets in the USA and other conventional assets in the DPI segment (NOK 42.7 billion), conventional offshore assets in the development phase in the DPN segment (NOK 8.7 billion) and a net impairment reversal of NOK 3.5 mainly related to a refinery in the MMP segment. See note 11 *Property, plant and equipment* to the Consolidated financial statements for further details.

Compared to 2014, the 32% increase in 2015 was mainly due to increased impairment charges primarily as a result of the further declining long-term commodity price assumptions in the first quarter of 2015. In addition, the USD/NOK exchange rate development and start-up and ramp-up of production of several fields added to the increase in depreciation. Reduced overall depreciation because of net impairments of assets in both 2014 and 2015 with a corresponding lower basis for depreciation partially offset the increase.

Depreciation, amortisation and net impairment losses increased by 40% in 2014 compared to 2013, mainly due to impairment losses related to Statoil's international operations, primarily driven by reduced short-term oil price forecasts. Also, new investments, higher production and increased asset retirement obligation, with a corresponding higher basis for depreciation, partly offset by increased estimates of proved reserves, added to increased depreciation costs in 2014 compared to 2013.

Exploration expenses (in NOK billion)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Exploration expenditures (activity)	**23.1**	23.9	21.8	(3%)	10%
Expensed, previously capitalised exploration expenditures	**1.7**	2.4	1.9	(28%)	26%
Capitalised share of current period's exploration activity	**(9.2)**	(7.3)	(6.9)	27%	6%
Impairments, net of reversals	**15.4**	11.3	1.2	36%	>100%
Exploration expenses	**31.0**	30.3	18.0	2%	69%

In 2015, **exploration expenses** were NOK 31.0 billion, a 2% increase compared to 2014 when exploration expenses were NOK 30.3 billion. In 2013, exploration expenses were NOK 18.0 billion

Exploration expenses were up 2% in 2015 mainly due to the USD/NOK exchange rate development and increased impairment of exploration prospects and signature bonuses in 2015. A lower level of drilling activity, a higher capitalisation rate and a lower portion of previously capitalised expenditures being expensed in 2015, partially offset the increase.

The increase in exploration expenses in 2014 compared to 2013 was mainly due to increased impairments of exploration prospects and signature bonuses internationally. Also, the cancellation of a rig contract in 2014 impacted exploration expenses negatively in 2014 compared to 2013.

As a result of the factors explained above, **net operating income** was NOK 14.9 billion in 2015, compared to NOK 109.5 billion in 2014. In 2013, net operating income was NOK 155.5 billion.

Net financial items were negative NOK 10.6 billion in 2015, compared to NOK 0.0 billion in 2014 and negative NOK 17.0 billion in 2013. The decrease in 2015 was mainly related to loss of NOK 3.8 billion on derivatives related to the long term debt portfolio in 2015, compared to a gain of NOK 5.8 billion in 2014, mainly due to changes in the interest yield curves.

In 2014, net financial items improved from negative NOK 17.0 billion in 2013 to NOK 0.0 billion mainly due to a positive change in currency derivatives used for currency and liquidity risk management as a result of changes in underlying currency positions and strengthening of USD towards NOK of 22.2% in 2014 compared to a strengthening of USD towards NOK of 9.3% in 2013. The improvement in 2014 also reflected a positive change on interest rate swap positions related to interest rate management of non-current bonds mainly due to decreased long term USD interest rates by an average of 0.6%-points in 2014 compared to an increase in 2013 by an average of 1.0%-points. These positive changes were partially offset by increased interest and other finance expenses in 2014.

Income taxes were NOK 41.6 billion in 2015, equivalent to an effective tax rate of more than 100%, compared to NOK 87.4 billion, equivalent to an effective tax rate of 79.9% in 2014. In 2013, income taxes were NOK 99.2 billion, equivalent to an effective tax rate of 71.7%.

In 2015, aggregated accounting losses were recognised in countries with higher than average tax rates, hence the "weighted average statutory tax rate" was negative. The **effective tax rate** in 2015 was primarily influenced by losses, mainly caused by impairments recognised in countries where deferred tax assets could not be recognised (NOK 23.5 billion), partially offset by tax exempted gains on sale of assets including Statoil's interest in the Shah Deniz project (NOK 3.7 billion) and the tax effect of foreign exchange losses in entities that are taxable in other currencies than the functional currency (NOK 5.8 billion). These losses are tax deductible, but do not impact the Consolidated statement of income. Furthermore, the effective tax rate in 2015 was influenced by the de-recognition of deferred tax assets within the Development and Production International segment, due to uncertainty related to future taxable income (NOK 4.7 billion), as described in Note 9 *Income taxes* to the Consolidated financial statements.

The effective tax rate in 2014 was primarily influenced by losses, mainly caused by impairments, recognised in countries where deferred tax assets could not be recognised (NOK 12.1 billion), partially offset by tax exempted gains on sale of assets including Norwegian continental shelf (NCS) and Statoil's interest in the Shah Deniz project (NOK 6.2 billion) and the tax effect of foreign exchange losses in entities that are taxable in other currencies than the functional currency (NOK 5.1 billion). These losses are tax deductible, but do not impact the Consolidated statement of income. The effective tax rate in 2014 was also influenced by the recognition of a non-cash tax income (NOK 2.0 billion) following a verdict in the Norwegian Supreme Court in February 2014. The Supreme Court voted in favour of Statoil in a tax dispute regarding the tax treatment of foreign exploration expenditures.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences) and changes in the relative composition of income between Norwegian oil and gas production, taxed at a marginal rate of 78%, and income from other tax jurisdictions. Other Norwegian income, including the onshore portion of net financial items, is taxed at 27% (28% in 2013), and income in other countries is taxed at the applicable income tax rates in those countries.

In 2015, **net income** was negative NOK 37.3 billion compared to positive NOK 22.0 billion in 2014 and NOK 39.2 billion in 2013.

The significant decrease from 2014 to 2015 was mainly due to the drop in prices, leading to lower earnings and impairment losses. Increased losses on net financial items related to derivatives added to the decrease, which was partially offset by the reduction in income taxes.

The 44% decrease in net income from 2013 to 2014 was mainly due to lower prices, resulting in reduced earnings and impairment losses. Increased exploration expenditures added to the decrease, whilst lower income taxes partially offset the decrease.

The board of directors proposes a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme starting from the fourth quarter 2015, subject to approval at the annual general meeting in line with the authorisation from May 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil, at a 5% discount for the fourth quarter 2015. The Norwegian Government, as majority shareholder, supports the proposal and will seek the Norwegian Parliament's approval to vote in favour of the proposal at the annual general meeting. The Norwegian government will match subscription of shares by minority shareholders, and thereby maintain its ownership share at 67% throughout the programme. See section 6.1 *Dividend policy* for more information.

Annual ordinary dividends for 2015 amounted to an aggregate total of NOK 23.5 billion. Annual ordinary dividends amounted to an aggregate total of NOK 22.9 billion and NOK 22.3 billion in 2014 and 2013, respectively.

In 2014, following a regular review process of Statoil's 2012 Consolidated financial statements, the Financial Supervisory Authority of Norway (the FSA), concluded that it had identified three errors related to interpretation and application of IFRS accounting principles for determination of cash generating units (CGUs) and impairment evaluations. For two of the matters, Statoil accepted the FSA's interpretations and has applied such interpretations in preparing the Consolidated financial statements. Statoil did not restate prior period financial statements as the impact was immaterial. For the third matter, Statoil does not accept the FSA's conclusion. In accordance with due process for such matters under Norwegian regulation, Statoil has appealed the order to the Norwegian Ministry of Finance, and has been granted a stay in carrying out the FSA's order pending the final outcome of the appeal. See note 23 *Other commitments, contingent liabilities and contingent assets* to the Consolidated financial statements for further details.

With effect from first quarter of 2016, Statoil will change to USD as presentation currency. The change reflects the company`s underlying exposure to the USD as well as better alignment of its reporting to peers.

4.1.3 Segment performance and analysis

Internal transactions in oil and gas volumes occur between our reporting segments before being sold in the market. The pricing policy for internal transfers is based on estimated market prices.

We eliminate intercompany sales when combining the results of reporting segments. Intercompany sales include transactions recorded in connection with our oil and natural gas production in DPN or DPI and also in connection with the sale, transportation or refining of our oil and natural gas production in MMP.

DPN produces oil and natural gas which is sold internally to MMP. A large share of the oil produced by DPI is also sold from MMP. The remaining oil and gas from DPI is sold directly in the market. For intercompany sales and purchases, Statoil has established a market-based transfer pricing methodology for the oil and natural gas that meets the requirements as to applicable laws and regulations.

Effective from the fourth quarter of 2013, revenues generated by the upstream segment in the United States are reported net of royalty interest. This change does not result in a change in net operating income. Historical information has been aligned to the current presentation, reflected in the following tables.

In 2015, the average transfer price for natural gas was NOK 1.58 per scm. The average transfer price was NOK 1.57 per scm in 2014 and NOK 1.92 in 2013. For oil sold from DPN to MMP, the transfer price is the applicable market-reflective price minus a cost recovery rate.

The following table shows certain financial information for the four reporting segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2015. For additional information please refer to note 3 *Segments* to the Consolidated financial statements.

	For the year ended 31 December		
(in NOK billion)	2015	2014	2013
Development & Production Norway			
Total revenues and other income	**139.5**	182.2	202.2
Net operating income	**57.6**	111.7	137.1
Non-current segment assets[1]	**244.1**	262.0	247.6
Development & Production International			
Total revenues and other income	**68.4**	85.2	81.9
Net operating income	**(66.9)**	(19.5)	16.4
Non-current segment assets[1]	**330.1**	333.8	286.5
Marketing, Midstream and Processing			
Total revenues and other income	**467.4**	597.3	608.6
Net operating income	**23.7**	16.2	2.6
Non-current segment assets[1]	**49.2**	46.3	39.3
Other			
Total revenues and other income	**3.2**	0.3	1.0
Net operating income	**(0.8)**	(1.5)	(1.1)
Non-current segment assets[1]	**6.1**	5.1	5.6
Eliminations[2]			
Total revenues and other income	**(195.7)**	(242.3)	(259.1)
Net operating income	**1.2**	2.6	0.4
Non-current segment assets[1]	-	-	-
Statoil group			
Total revenues and other income	**482.8**	622.7	634.5
Net operating income	**14.9**	109.5	155.5
Non-current segment assets[1]	**629.5**	647.3	578.9

1) Deferred tax assets, pension assets, equity accounted investments and non-current financial instruments are not allocated to segments.

2) Includes elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

The following tables show total revenues by geographic area.

2015 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	182.4	86.9	39.8	45.4	15.7	370.1
US	29.9	9.1	4.3	12.8	7.7	63.8
Sweden	0.0	0.0	0.0	14.2	1.0	15.2
Denmark	0.0	0.0	0.0	14.1	0.1	14.1
Other	10.8	3.6	0.1	0.0	5.4	19.8
Total revenues (excluding net income (loss) from equity accounted investments) and other income	223.1	99.6	44.2	86.5	29.8	483.1

2014 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	256.2	81.0	55.0	54.4	18.7	465.3
US	49.9	13.8	4.0	14.8	8.6	91.2
Sweden	0.0	0.0	0.0	16.5	1.7	18.2
Denmark	0.0	0.0	0.0	19.1	0.2	19.3
Other	18.6	4.4	0.4	0.0	5.4	28.8
Total revenues (excluding net income (loss) from equity accounted investments and other income	324.6	99.3	59.5	104.8	34.7	622.9

2013 Total revenues and other income by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	238.0	92.7	61.7	69.5	14.0	475.9
US	62.9	13.5	2.5	10.9	4.7	94.5
Sweden	0.0	0.0	0.0	17.2	(0.1)	17.1
Denmark	0.0	0.0	0.0	21.3	0.1	21.4
Other	20.6	4.2	0.3	0.0	0.4	25.5
Total revenues (excluding net income (loss) from equity accounted investments and other income	321.5	110.4	64.5	118.9	19.1	634.4

4.1.4 DPN profit and loss analysis

DPN net operating income was NOK 57.6 billion, down 48% compared to 2014 mainly driven by the drop in liquids prices and increased net impairment charges. Production of liquids and gas was up 3.9%.

The average daily production of liquids and gas (see section 9 *Terms and definitions*) was 1,232 mboe, 1,183 mboe and 1,217 mboe per day in 2015, 2014 and 2013, respectively.

The average daily total production of liquids and gas increased by 4% from 2014 to 2015, mainly due to ramp up of new fields, increased gas sales and good operational performance, partly offset by expected natural decline and divestments.

The average daily production of liquids and gas decreased by 3% from 2013 to 2014. This decrease was mainly due to expected natural decline and divestments, partially offset by new fields in production and higher production regularity in 2014 compared to 2013.

Over time, the volumes lifted and sold will equal entitlement production, but may be higher or lower in any period due to differences between the capacities and timing of the vessels lifting the volumes and the actual entitlement production during the period. See section 9 *Terms and definitions* for more information.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014	2013	15-14 change	14-13 change
Revenues	**138.1**	175.3	188.9	(21%)	(7%)
Net income from equity accounted investments	**0.0**	0.1	0.1	(62%)	18%
Other income	**1.4**	6.8	13.2	(79%)	(48%)
Total revenues and other income	**139.5**	182.2	202.2	(23%)	(10%)
Operating expenses and selling, general and administrative expenses	**(25.8)**	(25.2)	(27.4)	3%	(8%)
Depreciation, amortisation and net impairment losses	**(51.4)**	(40.0)	(32.2)	29%	24%
Exploration expenses	**(4.6)**	(5.4)	(5.5)	(14%)	(2%)
Net operating income	**57.6**	111.7	137.1	(48%)	(19%)

Total revenues and other income were NOK 139.5 billion in 2015, NOK 182.2 billion in 2014 and NOK 202.2 billion in 2013.

The 21% decrease in **revenues** from 2014 to 2015 was mainly due to reduced liquids prices. This was partly offset by a positive exchange rate development (NOK/USD), increased lifted volumes and increased gas prices. In addition, in 2015 a re-assessed valuation estimate of earn-out derivatives resulted in an unrealised fair value loss on derivatives and impacted revenues negatively.

The 7% decrease in **revenues** from 2013 to 2014 was mainly due to reduced gas and liquids prices and reduced lifted volumes of both liquids and gas, mainly caused by divestments and expected natural decline. This was partly offset by a positive exchange rate development (NOK/USD). In 2013, a re-assessed valuation estimate of earn-out derivatives resulted in an unrealised fair value loss on derivatives and impacted revenues negatively.

Other income in 2015 was impacted by gains from the sale of certain ownership interest on the NCS to Repsol of NOK 1.2 billion. Other income in 2014 was impacted by gains from the sale of certain ownership interests on the NCS to Wintershall of NOK 5.9 billion. Other income in 2013 was impacted by gains from sale of certain ownership interests on the NCS to OMV and Wintershall (NOK 13.0 billion).

As a result of the factors explained above, **total revenues and other income** decreased by 23% and 10% in 2015 and 2014, respectively.

Operating expenses and selling, general and administrative expenses were NOK 25.8 billion in 2015, compared to NOK 25.2 billion in 2014 and NOK 27.4 billion in 2013. In 2015, expenses increased compared to 2014 mainly due to gain related to changes in pension scheme in 2014 and ramp up of new field during 2015. This was partly offset by cost improvements and reduced turnaround activity level on several fields. In 2014 expenses decreased compared to 2013 mainly due to a gain related to changes in pension scheme and reduced operating costs at several fields due to divestments. This was partly offset by increased environmental tax expenses, operating preparations for new fields coming on stream and new fields commencing production during 2014.

Depreciation, amortisation and net impairment losses were NOK 51.4 billion in 2015, compared to NOK 40.0 billion in 2014 and NOK 32.2 billion in 2013. The increase of 29% from 2014 to 2015 was mainly due to a net impairment loss of NOK 8.6 billion in 2015 (primarily resulting from the reduced oil price forecast), new fields commencing production and ramp-up of new fields in 2015.The increase from 2013 to 2014 was mainly due to increased investments, new fields commencing production, increased asset retirement obligation with a corresponding higher basis for depreciations and an impairment loss. These effects were partly offset by reduced depreciation due to portfolio changes.

Exploration expenses were NOK 4.6 billion in 2015, compared to NOK 5.4 billion in 2014 and NOK 5.5 billion in 2013. The reduction from 2014 to 2015 was mainly due to lower drilling activity, a lower portion of previously capitalised exploration expenditures being expensed in 2015, and idle rig costs in 2014. The reduction from 2013 to 2014 was mainly due to lower drilling activity and less field development work due to sanctioning of Johan Sverdrup, offset by a higher portion of exploration expenditures capitalised in previous periods being expensed in 2014.

Net operating income in 2015 was NOK 57.6 billion, compared to NOK 111.7 billion in 2014 and NOK 137.1 billion in 2013. The NOK 54.0 billion decrease from 2014 to 2015 was mainly due to lower prices on liquids and increased depreciation and net impairment losses. The NOK 25.4 billion decrease from 2013 to 2014 was mainly due to lower prices on liquids and gas and increased depreciation and net impairment losses.

4.1.5 DPI profit and loss analysis

DPI results in 2015 were heavily impacted by lower prices and impairment losses. DPI delivered 6% growth in entitlement production, averaging 580 mboe per day.

The average daily equity liquids and gas production (see section 9 *Terms and definitions*) was 739 mboe in 2015, compared to 744 mboe in 2014 and 723 mboe in 2013. The decrease of 0.7% from 2014 to 2015 was driven primarily by the effect of the divestment of Shah Deniz (Azerbaijan) and a portion of Marcellus (US), and natural decline, primarily at mature fields in Angola. The decrease was partly offset by the ramp-up of fields, mainly CLOV (Angola) and Jack/St. Malo (US).

The increase of 3% from 2013 to 2014 was driven primarily by the ramp-up of fields, including Marcellus (US), CLOV and PSVM (Angola). The increase was partly offset by natural decline, primarily at mature fields in Angola, and the effect of the farm-down of Shah Deniz (Azerbaijan).

The average daily entitlement production of liquids and gas (see section 9 *Terms and definitions*) was 580 mboe per day in 2015, compared to 546 mboe per day in 2014 and 502 mboe per day in 2013. Entitlement production in 2015 was up by 6% due to the benefit of lower effect from production sharing agreements (PSA effect), mainly driven by the decrease in prices. The increase from 2013 to 2014 was driven by increased equity production as described above and a relatively lower PSA effect. The PSA effect was 116 mboe, 157 mboe and 182 mboe per day in 2015, 2014 and 2013, respectively.

Over time, the volumes lifted and sold will equal our entitlement production, but they may be higher or lower in any period due to differences between the capacity and timing of the vessels lifting our volumes and the actual entitlement production during the period. See section 9 *Terms and definitions* for more information.

Income statement under IFRS	For the year ended 31 December				
(in NOK billion)	2015	2014	2013	15-14 change	14-13 change
Revenues	**57.0**	80.2	78.1	(29%)	3%
Net income from equity accounted investments	**(0.8)**	(0.8)	(0.0)	1%	>100%
Other income	**12.2**	5.8	3.9	>100%	50%
Total revenues and other income	**68.4**	85.2	81.9	(20%)	4%
Purchases [net of inventory]	**(0.1)**	(0.0)	(0.1)	>100%	(85%)
Operating expenses and selling, general and administrative expenses	**(27.3)**	(22.9)	(21.0)	19%	9%
Depreciation, amortisation and net impairment losses	**(81.6)**	(56.8)	(31.9)	44%	78%
Exploration expenses	**(26.3)**	(25.0)	(12.5)	6%	100%
Net operating income	**(66.9)**	(19.5)	16.4	>100%	>(100%)

DPI generated **total revenues and other income** of NOK 68.4 billion in 2015 compared to NOK 85.2 billion in 2014 and NOK 81.9 billion in 2013.

Revenues in 2015 were negatively impacted by lower realised liquids and gas prices, partly offset by a positive currency effect from the NOK/USD development and an increase in lifted volumes. In addition, higher provisions relating to commercial disputes in 2015 compared to 2014 added to the decrease in total revenues. The increase from 2013 to 2014 was mainly caused by an increase in lifted volumes. In addition, lower provisions relating to commercial disputes in 2014 compared to 2013 positively impacted revenues. The increase was partly offset by lower realised liquids and gas prices, partly offset by a positive currency effect from the NOK/USD development.

Other income in 2015 was positively impacted by gains from sales of assets of NOK 12.2 billion in 2015 and NOK 5.8 billion in 2014, related primarily to the sale of ownership interest in the Shah Deniz project and the South Caucasus Pipeline. Other income in 2014 was also positively impacted by increased gains from sales of assets of NOK 2.3 billion.

As a result of the factors explained above, **total revenues and other income** decreased by 20% in 2015. In 2014, total revenues and other income increased by 4%.

Operating expenses and selling, general and administrative expenses were NOK 27.3 billion in 2015, compared to NOK 22.9 billion in 2014 and NOK 21.0 billion in 2013. The 19% increase from 2014 to 2015 was mainly due to the currency effect from the NOK/USD development. Production ramp-up on CLOV in Angola and start-up of the new fields Jack/St Malo in the US in 2014 added to the increase. Reduced operations and maintenance costs, lower royalties caused by lower prices and portfolio changes partially offset the increase. Excluding the USD/NOK exchange rate development, operating expenses and selling, general and administrative expenses decreased by 6%. The 9% increase from 2013 to 2014 was mainly due to higher operating and transportation expenses caused by production growth, primarily in North America. In addition, operating expenses increased due to the start-up of CLOV in 2014.

Depreciation, amortisation and net impairment losses were NOK 81.6 billion in 2015, compared to NOK 56.8 billion in 2014 and NOK 31.9 billion in 2013. The 44% increase from 2014 to 2015 was primarily caused by net impairment losses of NOK 42.7 billion in 2015, mainly related to unconventional onshore assets in North America and certain conventional upstream assets within the DPI reporting segment. The impairment losses resulted primarily from reduced short-term forward prices in combination with reduced long-term oil price forecasts. In addition, depreciation increased due to the NOK/USD development and higher production from start-up and ramp-up on various fields (CLOV, Jack/St Malo). The increases were partly offset by effect from net impairments in 2014 and 2015 and reduced depreciation from higher reserves estimates.

The 78% increase from 2013 to 2014 was mainly due to net impairment losses of NOK 23.8 billion in 2014, mainly related to the Kai Kos Dehseh oil sands project in Canada, unconventional onshore assets in North America and certain conventional upstream assets within the DPI reporting segment. The impairment losses were primarily resulting from reduced short-term oil price forecast. In addition, depreciation increased due to start-up and ramp-up of production from various fields (CLOV, PSVM, Eagle Ford and Bakken). The increases were partly offset by reduced depreciation from increased reserves and divestment of assets.

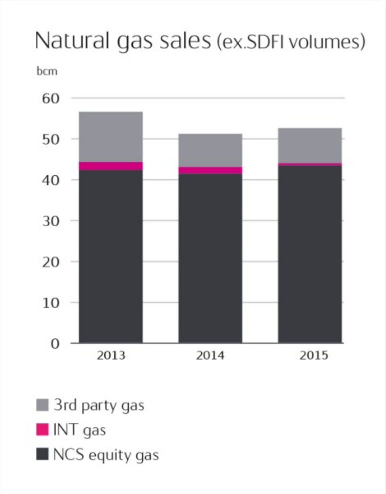
Exploration expenses were NOK 26.3 billion in 2015, compared to NOK 25.0 billion in 2014 and NOK 12.5 billion in 2013. The increase from 2014 to 2015 was mainly due to increased impairments of oil and gas prospects in the Gulf of Mexico, partly offset by a higher portion of exploration expenditure being capitalised in 2015.

Exploration expenses increased by NOK 12.5 billion from 2013 to 2014, primarily due to increased impairments of oil and gas prospects and signature bonuses and write-offs of exploration expenditures, mainly in Angola and the Gulf of Mexico. Also, the cancellation of a rig contract in 2014 impacted exploration expenses negatively in 2014.

Net operating income in 2015 was negative NOK 66.9 billion, compared to negative NOK 19.5 billion in 2014 and positive NOK 16.4 billion in 2013. The negative development from 2014 to 2015 was caused primarily by lower realised liquids and gas prices and impairment losses, and also by higher depreciations and higher operating expenses. The decrease from 2013 to 2014 was caused primarily by impairment losses, and also by lower realised liquids and gas prices, higher depreciations and higher operating expenses.

4.1.6 MMP profit and loss analysis

The 2015 results for MMP have been influenced by improved refining margins, solid liquids trading results and reversal of impairment losses from previous periods. The results were negatively impacted by lower margins for the European gas sales.

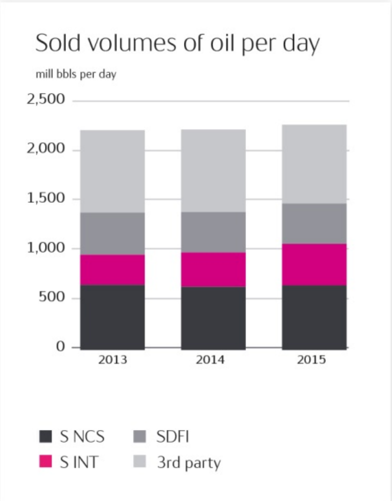


Total natural gas sales volumes were 52.6 bcm in 2015 (1.86 tcf), 51.2 bcm in 2014 (1.80 tcf) and 56.6 bcm (2.00 tcf) in 2013. The 3% increase in total gas volumes sold from 2014 to 2015 was related to higher entitlement production on the NCS in addition to higher third party volumes in Europe, partially offset by lower entitlement production internationally and lower third party volumes in the US. The 9% decrease in gas volumes sold from 2013 to 2014 was mainly related to lower third party volumes primarily in the US, and lower entitlement production on the NCS.

Third party natural gas sales volumes, as presented in the chart do not include volumes sold on behalf of the Norwegian State's direct financial interest (SDFI). MMP sold 37.2, 33.4 bcm and 35.0 bcm of NCS gas on behalf of SDFI in 2015, 2014 and 2013, respectively.

In 2015, the average invoiced natural gas sales price in Europe was NOK 2.16 per scm compared to NOK 2.28 per scm in 2014, a decrease of 5% mainly due to higher share of gas indexation in the gas contract portfolio and effect from drop in oil product prices on oil indexed contracts. LNG has a positive contribution on the European Gas price but less in 2015 as the LNG prices decreased by 23% from 2014 to 2015. The average invoiced natural gas sales price in Europe was approximately 7% lower in 2014 than in 2013, mainly due to general decrease in gas market prices partially offset by improved price premium vs. gas market prices in our gas contract portfolio. In 2015, the average invoiced natural gas sales price in North Americas was NOK 0.80 per scm compared to NOK 1.04 per scm in 2014, a decrease of 23% mainly due to a generally weaker gas market partially offset by USD/NOK exchange rate development. The average invoiced natural gas sales price in North Americas was approximately 25% higher in 2014 than in 2013, mainly due to high market prices in first quarter 2014 as a result of exceptionally cold weather in North East combined with long term pipeline capacity agreements enabling access to premium markets in Toronto and Manhattan.

All of Statoil's gas produced on the NCS is sold by MMP, purchased from DPN at a market-based internal price reduced by a cost cover element. Our average internal purchase price for gas was NOK 1.58 per scm in 2015, up 1% from NOK 1.57 per scm in 2014. Reduction in the market-based prices is offset by decreased cost element from 2014 to 2015.



Average crude, condensate and NGL sales were 2.3 mmbbl per day in 2015 of which approximately 1.07 mmbbl were sales of our equity volumes, 0.79 mmbbl sales of third-party volumes and 0.41 mmbbl sales of volumes purchased from SDFI. Our average sales volume was 2.2 mmbbl per day in 2014 and 2013. The average daily third-party volumes sold were 0.83 mmbbl in 2014 and 2013.

MMP's refining margin remained at a high level throughout 2015 reflecting lower crude oil prices and a strong demand for gasoline both in the US and China, while demand in Europe stopped falling. The outlook is that margins will continue to depend on gasoline markets with anticipated further growth in demand in Asia and with limited global capacity additions. Increasing global diesel demand, however, is offset by even higher production capacity. Statoil's refining reference margin was 8.0 USD/bbl in 2015, compared to 4.7 USD/bbl in 2014, an increase of 70%. The refining reference margin was 4.1 USD/bbl in 2013.

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2015	2014 (restated)	2013 (restated)	15-14 change	14-13 change
Revenues	**465.3**	593.0	607.7	(22%)	(2%)
Net income from equity accounted investments	**0.4**	0.5	0.1	(6%)	>100%
Other income	**1.7**	3.8	0.7	(55%)	>100%
Total revenues and other income	**467.4**	597.3	608.6	(22%)	(2%)
Purchases [net of inventory]	**(406.5)**	(544.2)	(565.2)	(25%)	(4%)
Operating expenses and selling, general and administrative expenses	**(37.6)**	(33.2)	(33.7)	13%	(2%)
Depreciation, amortisation and net impairment losses	**0.4**	(3.6)	(7.0)	>(100%)	(48%)
Net operating income	**23.7**	16.2	2.6	47%	>100%

Total revenues and other income were NOK 467.4 billion in 2015, compared to NOK 597.3 billion in 2014 and NOK 608.6 billion in 2013.

The decrease in **revenues** from 2014 to 2015 was mainly due to decrease in crude and gas prices, partially offset by higher volumes for crude, other oil products and gas sold. The average crude price in USD declined by approximately 47% in 2015 compared to 2014, partially offset by weakening USD/NOK average daily exchange rate by approximately 28% in 2015. Revenues in 2015 were positively impacted by gains from derivatives, mainly due to significant drop in the forward curve in the oil and gas market.

The decrease in revenues from 2013 to 2014 was mainly due to decrease in gas and crude prices plus lower volumes of gas sold. The average crude price in USD declined by approximately 9% in 2014 compared to 2013, partially offset by weakening USD/NOK average daily exchange rate by approximately 7% in 2014. Revenues in 2014 were positively impacted by gains from derivatives, mainly due to significant drop in the forward curve in the oil market.

Other income in 2015 was positively impacted by gain on sale of assets of NOK 1.7 billion. In 2014, other income was positively impacted by the Sonatrach Arbitration Settlement of NOK 2.8 billion, following an arbitration ruling in Statoil's favour.

As a result of the factors explained above, **total revenues and other income** decreased by 22% and 2% in 2015 and 2014, respectively.

Purchases [net of inventory] were NOK 406.5 billion in 2015, compared to NOK 544.2 billion in 2014 and NOK 565.2 billion in 2013. The decrease from 2014 to 2015 was mainly due to decrease in crude and gas prices and lower volumes of crude, other oil products and gas sold. The decrease from 2013 to 2014 was mainly due to decrease in gas and crude prices, lower volumes of gas sold and losses on storages due to a significant price reduction.

Operating expenses and selling, general and administrative expenses were NOK 37.6 billion in 2015, compared to NOK 33.2 billion in 2014 and NOK 33.7 billion in 2013. The increase from 2014 to 2015 was mainly due to negative USD/NOK currency effects and onerous contract provisions of NOK 1.6 billion in 2015. This was partially offset by cost reduction due to improvement initiatives. Excluding the USD/NOK exchange rate development, operating expenses and selling, general and administrative expenses were at the same level as last year.

The Cove Point onerous contract provision of NOK 4.1 billion influenced expenses in 2013. Excluding that item, 2014 figures would show an increase in expenses as compared to 2013. The increase was mainly caused by increased activity in the US in addition to negative NOK/USD currency effects.

Depreciation, amortisation and net impairment losses amounted to an income of NOK 0.4 billion in 2015, compared to losses of NOK 3.6 billion in 2014 and NOK 7.0 billion in 2013. The decrease in depreciation, amortisation and net impairment losses from 2014 to 2015 was mainly caused by net reversal of impairment charges of NOK 3.5 billion in 2015. The reversal of impairment was triggered by increased refinery margins and operational improvements. The decrease in depreciation, amortisation and net impairment losses from 2013 to 2014 was mainly as a result of impairment losses of the refineries made in 2013.

Net operating income was NOK 23.7 billion, NOK 16.2 billion, NOK 2.6 billion in 2015, 2014 and 2013, respectively. The increase of NOK 7.5 billion from 2014 to 2015 was mainly due to higher refining margins and solid liquids trading results in addition to negative USD/NOK foreign exchange rate development and net reversal of impairment charges of NOK 3.5 billion, These increases were partially offset by the Sonatrach Arbitration Settlement of NOK 2.8 billion in 2014 in Statoil's favour, and lower margins for the European gas sales.

The increase of NOK 13.6 billion from 2013 to 2014 was mainly due to lower impairment losses in 2014 compared to 2013, the Sonatrach Arbitration Settlement of NOK 2.8 billion in 2014 in Statoil's favour, the onerous contract provision related to Cove Point of NOK 4.1 billion in 2013, and improved margins on gas in Europe including LNG arbitrage and stronger contribution from US gas sales due to an exceptionally cold winter in the North East US.

Further, net operating income increased due to improved refining margins and increased result related to ownership in infrastructure. These increases were partially offset by losses on operational storages in 2014 due to reduced prices.

4.1.7 Other operations

The Other reporting segment includes activities within New Energy Solutions; Global Strategy and Business Development; Technology, Projects and Drilling; and Corporate staffs and support functions.

In 2015, the Other reporting segment recorded a net operating loss of NOK 0.8 billion compared to a net operating loss of NOK 1.5 billion in 2014 and a net operating loss of NOK 1.1 billion in 2013.

4.2 Liquidity and capital resources

We believe that our established liquidity reserves, credit rating and access to capital markets provide us with sufficient working capital for our foreseeable requirements.

4.2.1 Review of cash flows

Statoil`s cash flows in 2015 reflect a high investment level, continued portfolio optimisation and issuance of new debt resulting in a small decrease in cash and cash equivalents and increase in short-term financial investments.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	2015	2014	Full year 2013
Income before tax		**4.3**	109.4	138.4
Depreciation, amortisation and net impairment losses	11, 12	**133.8**	101.4	72.4
Exploration expenditures written off	12	**17.1**	13.7	3.1
(Gains) losses on foreign currency transactions and balances		**(0.4)**	(3.1)	4.8
(Gains) losses from dispositions	4	**(17.3)**	(12.4)	(17.6)
(Increase) decrease in other items related to operating activities		**19.8**	3.9	6.6
(Increase) decrease in net derivative financial instruments	25	**9.2**	(2.8)	11.7
Interest received		**2.9**	2.1	2.1
Interest paid		**(3.6)**	(3.4)	(2.5)
Cash flows provided by operating activities before taxes paid and working capital items		**165.8**	208.8	218.8
Taxes paid		**(65.7)**	(96.6)	(114.2)
(Increase) decrease in working capital		**8.9**	14.2	(3.3)
Cash flows provided by operating activities		**109.0**	126.5	101.3
Additions through business combinations	4	**(3.5)**	0.0	0.0
Capital expenditures and investments		**(124.7)**	(122.6)	(114.9)
(Increase) decrease in financial investments		**(19.8)**	(12.7)	(23.2)
(Increase) decrease in other non-current items		**(0.3)**	0.8	0.6
Proceeds from sale of assets and businesses	4	**33.2**	22.6	27.1
Cash flows used in investing activities		**(115.1)**	(112.0)	(110.4)
New finance debt	18	**32.2**	20.6	62.8
Repayment of finance debt		**(11.4)**	(9.7)	(7.3)
Dividend paid	17	**(22.9)**	(33.7)	(21.5)
Net current finance debt and other		**(5.5)**	(0.3)	(7.3)
Cash flows provided by (used in) financing activities		**(7.5)**	(23.1)	26.6
Net increase (decrease) in cash and cash equivalents		**(13.6)**	(8.6)	17.5
Effect of exchange rate changes on cash and cash equivalents		**7.1**	5.7	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	**82.4**	85.3	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	16	**75.9**	82.4	85.3

Cash flows provided by operations
The most significant drivers of cash flows provided by operations were the level of production and prices for liquids and natural gas that impact revenues, purchases [net of inventory], taxes paid and changes in working capital items.

Cash flows provided by operating activities were NOK 109.0 billion in 2015 compared to NOK 126.5 billion in 2014, which is a decrease of NOK 17.5 billion. Cash flows provided by operating activities before taxes paid and working capital items were reduced by NOK 43.0 billion compared to 2014, driven by a significant reduction in both liquids and gas prices measured in NOK. The decrease was partially offset by positive changes in working capital and lower taxes paid in 2015 compared to 2014.

Cash flows provided by operating activities were NOK 126.5 billion in 2014 compared to NOK 101.3 billion in 2013, an increase of NOK 25.2 billion. Cash flows provided by operating activities before taxes paid and working capital items were reduced by NOK 10.0 billion compared to 2013, driven by decreased profitability mainly caused by lower prices for liquids and European gas. The decrease was more than offset by positive changes in working capital and lower taxes paid in 2014 compared to 2013.

Cash flows used in investing activities
Cash flows used in investing activities were NOK 115.1 billion in 2015 compared to NOK 112.0 billion in 2014, an increase of NOK 3.1 billion mainly due to increased capital expenditures, financial investments and additions through business combinations, partially offset by higher proceeds from sale of assets and businesses. The proceeds from sale of assets in 2015 of NOK 33.2 billion were mainly related to the divestment of the remaining interests in the Shah Deniz field and the South Caucasus pipeline, sale of office buildings, sale of interest in the Marcellus onshore play, sale of interests in Trans Adriatic pipeline AG and the sale of interests in licences on the NCS.

Cash flows used in investing activities were NOK 112.0 billion in 2014 compared to NOK 110.4 billion in 2013, an increase of NOK 1.6 billion mainly due to increased capital expenditures, partly offset by lower investments in deposits with more than three months maturity. The proceeds from sale of assets in 2014 of NOK 22.6 billion were mainly related to the divestment of interests in the Shah Deniz field and the South Caucasus pipeline and the sale of interests in licences on the NCS.

Cash flows provided by (used in) financing activities
Cash flows used in financing activities were NOK 7.5 billion in 2015 and were mainly related to payments of dividends NOK 22.9 and repayments of debt NOK 11.4, partially offset by issuance of new debt of NOK 32.2 billion. Cash flows used in financing activities were NOK 23.1 billion in 2014 and were mainly related to payments of dividends and repayments of debt, partly offset by issuance of new debt in November 2014 of NOK 20.6 billion. The amounts reported in 2013 were influenced by debt issuances of NOK 62.8 billion in total.

4.2.2 Financial assets and debt

Statoil has a strong balance sheet and considerable financial flexibility. The net debt ratio before adjustments was 25.6% at the end of 2015. Net interest-bearing debt before adjustments increased by NOK 32.8 billion in 2015 and was NOK 122.0 billion at the end of 2015.

Financial position and liquidity
Statoil's financial position is strong although its net debt ratio before adjustments at year end increased from 19.0% in 2014 to 25.6% in 2015. Net interest-bearing debt increased from NOK 89.2 billion to NOK 122.0 billion. During 2015 Statoil's total equity decreased from NOK 381.2 billion to NOK 355.1 billion, mainly due to impairments recognised in 2015. Current level of net debt ratio is below levels from previous periods of low prices. Cash flows provided by operating activities were reduced in 2015 mainly due to lower prices and increased cash flows used in investments. Statoil introduced USD as its dividend declaration currency in the second quarter of 2015 announcement and has paid out four quarterly dividends in 2015. For the fourth quarter of 2015 the board of directors will propose to the annual general meeting (AGM) to maintain a dividend of USD 0.2201 per share for the fourth quarter 2015 and to introduce a two-year scrip dividend programme starting from the fourth quarter 2015. For details see section 6.1.1 *Dividends*.

Statoil believes that, given its current liquidity reserves, including committed credit facilities of USD 5.0 billion and its access to various capital markets, Statoil will have sufficient capital available to meet its liquidity needs.

Funding needs arise as a result of Statoil's general business activity. Statoil generally seek to establish financing at the corporate level. Project financing may be used in cases involving joint ventures with other companies. Statoil aims to have access at all times to a variety of funding sources in respect of markets and instruments as well as maintaining relationships with a core group of international banks that provide various kinds of banking services.

Statoil has credit ratings from Moody's and Standard & Poor's (S&P). These ratings ensure necessary predictability when it comes to funding access at attractive terms and conditions. Our current long-term ratings are Aa2 and A+ from Moody's and S&P, respectively. The S&P rating was revised from AA- on credit watch negative to A+ with stable outlook on 22 February 2016. Moody's placed Statoil and its peers on review for downgrade on 22 January 2016. As of the date of this Annual Report on Form 20-F, Moody`s review of Statoil's rating had not yet concluded. Both rating agency reviews have been triggered by low oil prices. The short-term ratings are P-1 from Moody's and A-1 from S&P. In order to maintain financial flexibility going forward, we intend to keep key financial ratios at levels consistent with our objective of maintaining Statoil's long-term credit rating at least within the single A category on a stand-alone basis.

The management of financial assets and liabilities takes into consideration funding sources, the maturity profile of non-current debt, interest rate risk, currency risk and available liquid assets. Statoil's borrowings are denominated in various currencies and normally swapped into USD. In addition, interest rate derivatives, primarily interest rate swaps are used, to manage the interest rate risk of our long-term debt portfolio. The Group's central treasury unit manages the funding and liquidity activities at Group level.

We have diversified our cash investments across a range of financial instruments and counterparties to avoid concentrating risk in any one type of investment or any single country. As of 31 December 2015, approximately 6% of our liquid assets were held in USD-denominated assets, 17% in NOK, 51% in EUR, 7% in DKK, 15% in SEK, and 1% in GBP, before the effect of currency swaps and forward contracts. Approximately 72% of our liquid assets were held in treasury bills and commercial papers, 23% in time deposits, 3% in money market funds and 2% at available bank deposits. As of 31 December 2015, approximately 3% of our liquid assets were classified as restricted cash (including collateral deposits).

Our general policy is to keep a liquidity reserve in the form of cash and cash equivalents or other current financial investments in our balance sheet, as well as committed, unused credit facilities and credit lines in order to ensure that we have sufficient financial resources to meet our short-term requirements.

Long-term funding is raised when we identify a need for such financing based on our business activities, cash flows and required financial flexibility or when market conditions are considered to be favourable. Bond transactions were made in 2015 at very favourable terms, pre-funding longer-term commitments.

The group's borrowing needs are usually covered through the issuing of short-, medium- and long-term securities, including utilisation of a US Commercial Paper Programme (programme limit USD 4.0 billion) and a Shelf Registration Statement (unlimited) filed with the Securities and Exchange Commission (SEC) in the USA as well as through issues under a Euro Medium-Term Note (EMTN) Programme (programme limit updated to EUR 20.0 billion 5 February, 2016) listed on the London Stock Exchange. Committed credit facilities and credit lines may also be utilised. After the effect of currency swaps, the major part of our borrowings is in USD.

During 2015 Statoil issued bonds with maturities from four to 20 years for a total amount of EUR 3.75 billion (NOK 32.1 billion). The bonds were issued in EUR and swapped into USD. All of the bonds are unconditionally guaranteed by Statoil Petroleum AS. For more information see note 18 *Finance debt*.

Statoil issued new debt securities in 2014 equivalent to NOK 20.5 billion and in 2013 equivalent to NOK 62.8 billion.

Financial indicators

Financial indicators (in NOK billion)	For the year ended 31 December 2015	2014	2013
Gross interest-bearing financial liabilities [1]	**284.5**	231.6	182.5
Net interest-bearing liabilities before adjustments	**122.0**	89.2	58.0
Net debt to capital employed ratio [2]	**25.6%**	19.0%	14.0%
Net debt to capital employed ratio adjusted [3]	**26.8%**	20.0%	15.2%
Cash and cash equivalents	**76.0**	83.1	85.3
Current financial investments	**86.5**	59.2	39.2
ROACE [4]	**(8.0%)**	2.7%	11.3%
Ratio of earnings to fixed charges [5]	**1.1**	9.4	7.5

1) Defined as non-current and current finance debt.

2) As calculated according to IFRS. Net debt to capital employed ratio is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and current financial investments. Capital employed is net debt, shareholders' equity and minority interest.

3) In order to calculate the net debt to capital employed ratio adjusted, Statoil makes adjustments to capital employed as it would be reported under IFRS to adjust for project financing exposure that does not correlate to the underlying exposure and to add into the capital employed measure interest-bearing elements which are classified together with non-interest-bearing elements under IFRS. See section 4.4.2 *Net debt to capital employed ratio* below for a reconciliation of capital employed and a description of why Statoil makes use of this measure.

4) ROACE is equal to net income adjusted for financial items after tax, divided by average capital employed over the last 12 months. See section 4.4.1 *Return on average capital employed (ROACE)* for a reconciliation of ROACE and a description of why Statoil makes use of this measure.

5) Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortisation of capitalised interest and (iv) fixed charges (which have been adjusted for capitalised interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalised interest) and estimated interest within operating leases.

Gross interest-bearing debt

Gross interest-bearing debt was NOK 284.5, NOK 231.6 billion and NOK 182.5 billion at 31 December 2015, 2014 and 2013, respectively. The NOK 52.9 billion increase from 2014 to 2015 was due to an increase in non-current finance debt of NOK 58.9 billion, offset by a reduction in current finance debt of NOK 6.0 billion. The NOK 49.0 billion increase from 2013 to 2014 was due to an increase in current finance debt of NOK 9.4 billion and an increase in non-current finance debt of NOK 39.6 billion. Our weighted average annual interest rate was 3.39%, 3.78% and 4.06% at 31 December 2015, 2014 and 2013, respectively. Our weighted average maturity on finance debt was nine years at 31 December 2015, compared to nine years at 31 December 2014 and 10 years at 31 December 2013.

Net interest-bearing debt
Net interest-bearing debt before adjustments were NOK 122.0 billion, NOK 89.2 billion and NOK 58.0 billion at 31 December 2015, 2014 and 2013, respectively. The increase of NOK 32.8 billion from 2014 to 2015 was mainly related to an increase in gross interest-bearing debt of NOK 52.9 billion offset in part by an increase in cash and cash equivalents and current financial investments of NOK 20.1 billion mainly due to negative net cash flow in 2015. The increase of NOK 31.2 billion from 2013 to 2014 was mainly related to an increase in gross interest-bearing debt of NOK 49.0 billion offset in part by an increase in cash and cash equivalents and current financial investments of NOK 17.9 billion.

The net debt to capital employed ratio
The net debt to capital employed ratio before adjustments was 25.6%, 19.0% and 14.0% in 2015, 2014 and 2013 respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote three above) was 26.8%, 20.0% and 15.2% in 2015, 2014, and 2013, respectively. The 6.8 percentage points increase in net debt to capital employed ratio adjusted from 2014 to 2015 was related to the increase in net interest-bearing debt adjusted of NOK 34.4 billion in combination with an increase in capital employed adjusted of NOK 8.3 billion. The 4.8 percentage points increase in net debt to capital employed ratio adjusted from 2013 to 2014 was related to an increase in net interest-bearing debt adjusted of NOK 31.9 billion in combination with an increase in capital employed adjusted of NOK 57.0 billion.

Cash, cash equivalents and current financial investments
Cash and cash equivalents were NOK 76.0 billion, NOK 83.1 billion and NOK 85.3 billion at 31 December 2015, 2014 and 2013 respectively. See note 16 *Cash and cash equivalents* to the Consolidated financial statements for information concerning restricted cash. Current financial investments, which are part of our liquidity management, amounted to NOK 86.5 billion, NOK 59.2 billion and NOK 39.2 billion at 31 December 2015, 2014 and 2013, respectively.

4.2.3 Investments

Organic capital expenditures (excluding acquisitions, capital leases and other investments with significant different cash flow pattern) amounted to USD 14.7 billion, or NOK 118.8 billion, for the year ended 31 December 2015.

Capital expenditures, defined as additions to property, plant and equipment (including capitalised financial leases), capitalised exploration expenditures, intangible assets, long-term share investments and investments in equity accounted companies, amounted to NOK 125.5 billion for the year ended 2015. The capital expenditure level ended below original guidance due to reduced activity level and increased efficiency. This was partly offset by the development in the USDNOK exchange rate.

In 2014, capital expenditures were NOK 125.1 billion compared to NOK 117.4 billion in 2013. The increase was primarily related to higher activity level in Development and Production International.

Organic capital expenditures (excluding acquisitions, capital leases and other investments with significant different cash flow pattern) amounted to NOK 118.8 billion for the year ended 2015, or USD 14.7 billion. In 2014, organic capital expenditures amounted to NOK 121.6 billion, or USD 19.6 billion.

The section describes our estimated organic capital expenditure for 2016 relating to potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration. The figure is based on Statoil developing organically, and it excludes possible expenditures relating to acquisitions. The expenditure estimates and descriptions of investments in the segment descriptions below could therefore differ materially from the actual expenditure. Organic capital expenditures are estimated to be around USD 13 billion in 2016.

Statoil finances its capital expenditures both internally and externally. For more information see section 4.2.2 *Financial assets and debt*.

In Norway a substantial proportion of our 2016 capital expenditures will be spent on ongoing development projects such as Johan Sverdrup, Gina Krog and Aasta Hansteen, in addition to various extensions, modifications and improvements on currently producing fields like Gullfaks, Oseberg and Troll.

Internationally we currently estimate that a substantial proportion of our 2016 capital expenditure will be spent on the following ongoing and planned development projects: Mariner in UK and Julia, Stampede and Bakken in the US.

In midstream and downstream we currently estimate that most of the 2016 capital expenditures will be spent on Polarled and Johan Sverdrup export pipelines, in addition to processing and transportation solutions related to Bakken, Marcellus and Eagle Ford in the US.

As illustrated in the section 4.2.5 *Principal contractual obligations,* Statoil have committed to certain investments in the future. The further into the future, the more flexibility we will have to revise expenditure. This flexibility is partly dependent on the expenditure our partners in joint ventures agree to commit to. A large part of the capital expenditure for 2016 is committed.

Statoil may alter the amount, timing or segmental or project allocation of our capital expenditures in anticipation of or as a result of a number of factors outside our control.

4.2.4 Impact of reduced prices

Our results are affected by the development in the price of raw materials and services that are necessary for the development and operation of oil and gas producing assets.

Cost development in the prices of goods, raw materials and services that are necessary for the development and operation of oil and gas producing assets can vary considerably over time and between each market segment.

The reduction in the oil price has been driving a decrease in commodities prices. Prices in supplier markets have been reduced and in several supplier market segments Statoil has achieved reduced rates compared to the 2013/2014 level. Such savings have been achieved both in new and renegotiated contracts. While some of the cost reductions relates to capitalised expenditures and thus only affects our annual results through decreased depreciation, certain elements of operating expenditures have also been affected by this cost reduction.

See the analysis of profit and loss in section 4.1 *Operating and financial review* as well section 2.3 *Group Outlook*.

4.2.5 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2015.

The table includes contractual obligations, but excludes derivatives and other hedging instruments as well as asset retirement obligations, as these obligations for the most part are expected to lead to cash disbursements more than five years in the future. Obligations payable by Statoil to unconsolidated equity affiliates are included gross in the table. Where Statoil includes both an ownership interest and the transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. See section 5.2.3 *Disclosures about market risk* for more information.

Contractual obligations (in NOK billion)	As at 31 December 2015 Payment due by period [1] Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current finance debt	19.0	72.0	81.1	207.5	379.6
Minimum operating lease payments	25.6	28.8	17.6	27.8	99.8
Nominal minimum other long-term commitments[2]	13.5	24.6	23.1	77.9	139.1
Total contractual obligations	58.1	125.4	121.8	313.2	618.5

1) "Less than 1 year" represents 2015; "1-3 years" represents 2016 and 2017, "3-5 years" represents 2018 and 2019, while "More than 5 years" includes amounts for later periods.

2) For further information see note 23 *Other commitments and contingencies* to the Consolidated financial statements.

Non-current finance debt in the table represents principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 18 *Finance debt* and note 22 *Leases* to the Consolidated financial statements.

Statoil had contractual commitments of NOK 62.3 billion at 31 December 2015. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

Statoil's projected pension benefit obligation was NOK 60.1 billion, and the fair value of plan assets amounted to NOK 45.2 billion as of 31 December 2015. Company contributions are mainly related to employees in Norway. In 2014 Statoil ASA made a decision to change the company's pension plan in Norway from a defined benefit plan to a defined contribution plan. The actual transitioning to the defined contribution plan took place in 2015, see note 19 *Pensions* to the Consolidated financial statements for more information.

4.2.6 Off balance sheet arrangements

This section describes various agreements that are not recognised in the balance sheet, such as operational leases and transportation and processing capacity contracts.

We have entered into various agreements, such as operational leases and transportation and processing capacity contracts, that are not recognised in the balance sheet. For more information, see section 4.2.5 *Principal contractual obligations* and note 22 *Leases* to the Consolidated financial statements.

Statoil is party to certain guarantees, commitments and contingencies that, pursuant to IFRS, are not necessarily recognised in the balance sheet as liabilities. See note 23 *Other commitments and contingencies* to the Consolidated financial statements for more information.

4.3 Accounting Standards (IFRS)

We prepare our Consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU and as issued by the International Accounting Standards Board.

We prepared our first set of Consolidated financial statements pursuant to IFRS for 2007. The IFRS standards have been applied consistently to all periods presented in the Consolidated financial statements and when preparing an opening IFRS balance sheet as of 1 January 2006 (subject to certain exemptions allowed by IFRS 1) for the purpose of the transition to IFRS.

See note 2 *Significant accounting policies* to the Consolidated financial statements for a discussion of key accounting estimates and judgements.

4.4 Non-GAAP measures

This section describes the non-GAAP financial measures that are used in this report.

We are subject to SEC regulations regarding the use of "non-GAAP financial measures" in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance with generally accepted accounting principles, which in our case refers to IFRS.

The following financial measures may be considered non-GAAP financial measures:

- Return on average capital employed (ROACE)
- Net debt to capital employed ratio before adjustments
- Net debt to capital employed ratio adjusted
- Organic capital expenditures
- Production cost per boe of entitlement volumes

For information regarding Organic capital expenditures see section 4.2.3 *Investments*.
For information regarding Production cost per barrel of entitlement volumes see note 27 *Supplementary oil and gas information (unaudited)* to the Consolidated financial statements.

4.4.1 Return on average capital employed (ROACE)

We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt.

In the group's view, this measure provides useful information for both the group and investors about performance during the period under evaluation. We make regular use of this measure to evaluate our operations. Our use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with generally accepted accounting principles or ratios based on these figures.

ROACE was negative 8.0% in 2015 compared to 2.7% in 2014 and 11.3% in 2013. The decrease from last year is due to the negative development in net income adjusted for financial items, combined with an increase in average capital employed.

Calculation of numerator and denominator used in ROACE calculation	For the year ended 31 December				
(in NOK billion, except percentages)	2015	2014	2013	15-14 change	14-13 change
Net income for the year	(37.3)	22.0	39.2		
-Net financial items	(10.6)	(0.0)			
-Tax on financial items	10.2	9.2			
+Accretion expense net after tax	(1.0)	(1.1)			
+Net financial items adjusted after tax[1)]			4.6		
Net income adjusted for financial Items after tax (A1)	(37.9)	11.8	43.9	>(100%)	(73%)
Capital employed before adjustments to net interest-bearing debt: [2)]					
Year End 2015	477.1				
Year End 2014	470.4	470.4			
Year End 2013		414.0	414.0		
Year End 2012			359.2		
Sum of capital employed for two years (B1)	947.5	884.4	773.2		
Calculated average capital employed:					
Average capital employed before adjustments to net interest-bearing debt (B1/2)	473.8	442.2	386.6	7%	14%
Calculated ROACE:					
Return on average capital employed (A1/(B1/2))	(8.0%)	2.7%	11.3%	>(100%)	(77%)

1) Calculation of financial items is revised for 2015 and 2014 ROACE definition. Net financial items after tax for 2013 includes financial items adjusted of negative NOK 4.6 billion and tax on financial items of NOK 9.2 billion.

2) Capital employed before adjustments for each year is reconciled in the table in the section 4.4.2 *Net debt to capital employed ratio*.

4.4.2 Net debt to capital employed ratio

In the Company's view, the calculated net debt to capital employed ratio gives a more complete picture of the Group's current debt situation than gross interest-bearing financial liabilities.

The calculation uses balance sheet items relating to gross interest bearing financial liabilities and adjusts for cash, cash equivalents and current financial investments. Certain adjustments are made, since different legal entities in the Group lend to projects and others borrow from banks. Project financing through an external bank or similar institution will not be netted in the balance sheet and will over-report the debt stated in the balance sheet in relation to the underlying exposure in the Group. Similarly, certain net interest-bearing debts incurred from activities pursuant to the Owners Instruction from the Norwegian State are set off against receivables on the Norwegian State's direct financial interest (SDFI).

The net interest-bearing debt adjusted for these two items is included in the average capital employed.

The table below reconciles the net interest-bearing liabilities adjusted, capital employed and net debt to capital employed adjusted ratio with the most directly comparable financial measure or measures calculated in accordance with IFRS.

Calculation of capital employed and net debt to capital employed ratio (in NOK billion, except percentages)	For the year ended 31 December 2015	2014	2013
Shareholders' equity	354.7	380.8	355.5
Non-controlling interests (Minority interest)	0.3	0.4	0.5
Total equity (A)	355.1	381.2	356.0
Current bonds, bank loans, commercial papers and collateral liabilities	20.5	26.5	17.1
Bonds, bank loans and finance lease liabilities	264.0	205.1	165.5
Gross interest-bearing financial liabilities (B)	284.5	231.6	182.5
Cash and cash equivalents	76.0	83.1	85.3
Current financial investments	86.5	59.2	39.2
Cash and cash equivalents and current financial investments (C)	162.4	142.3	124.5
Net interest-bearing liabilities before adjustments (B1) (B-C)	122.0	89.2	58.0
Other interest-bearing elements [1]	9.8	8.0	7.1
Marketing instruction adjustment [2]	(1.9)	(1.6)	(1.3)
Adjustment for project loan [3]	0.0	(0.1)	(0.2)
Net interest-bearing liabilities adjusted (B2)	129.9	95.6	63.6
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing liabilities (A+B1)	477.1	470.4	414.0
Capital employed adjusted (A+B2)	485.0	476.7	419.6
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	25.6%	19.0%	14.0%
Net debt to capital employed adjusted (B2/(A+B2)	26.8%	20.0%	15.2%

1) Other interest-bearing elements are cash and cash equivalents adjustments regarding collateral deposits classified as cash and cash equivalents in the Consolidated balance sheet but considered as non-cash in the non-GAAP calculations as well as financial investments in Statoil Forsikring AS classified as current financial investments.

2) Marketing instruction adjustment is an adjustment to gross interest bearing financial debt due to the SDFI part of the financial lease in the Snøhvit vessels that are included in Statoil's Consolidated balance sheet.

3) Adjustment for project loan is adjustment to gross interest-bearing debt due to the BTC project loan structure.

5 Risk review

Statoil's overall risk management includes identifying, evaluating and managing risk in all its activities to ensure safe operations and to achieve Statoil's corporate goals.

5.1 Risk factors

Statoil is exposed to a number of risks that could affect its operational and financial performance. In this section, some of the key risk factors are addressed.

5.1.1 Risks related to our business

This section describes the most significant potential risks relating to Statoil's business:

A prolonged period of low oil and/or natural gas prices would have a material adverse effect on Statoil.
The prices of oil and natural gas have fluctuated greatly in response to changes in many factors. Currently, Statoil is in a situation where oil and natural gas prices have declined substantially compared to levels seen over the last few years. There are several reasons for this decline, but fundamental market forces beyond the control of Statoil or other similar market participants have impacted and can continue to impact oil and natural gas prices in the future.

Generally, Statoil does not and will not have control over the factors that affect the prices of oil and natural gas. These factors include:
- economic and political developments in resource-producing regions
- global and regional supply and demand
- the ability of the Organisation of the Petroleum Exporting Countries (Opec) and/or other producing nations to influence global production levels and prices
- prices of alternative fuels that affect the prices realised under Statoil's long-term gas sales contracts
- government regulations and actions; including changes in energy and climate policies
- global economic conditions
- war or other international conflicts
- changes in population growth and consumer preferences
- the price and availability of new technology and
- weather conditions

It is impossible to predict future price movements for oil and/or natural gas with certainty. A prolonged period of low oil and natural gas prices will adversely affect Statoil's business, the results of operations, financial condition, liquidity and Statoil's ability to finance planned capital expenditure, including possible reductions in capital expenditures which could lead to reduced reserve replacement. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could, if deemed to have longer term impact, lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect the management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the results of Statoil's operations in the period in which it occurs. Changes in management's view on long-term oil and/or natural gas prices or further material reductions in oil, gas and/or product prices could have an adverse impact on the economic viability of projects that are planned or in development.

Statoil's crude oil and natural gas reserves are only estimates and Statoil's future production, revenues and expenditures with respect to its reserves may differ materially from these estimates.
The reliability of proved reserve estimates depends on:
- the quality and quantity of Statoil's geological, technical and economic data
- the production performance of Statoil's reservoirs
- extensive engineering judgments and
- whether the prevailing tax rules and other government regulations, contracts and oil, gas and other prices will remain the same as on the date estimates are made

Proved reserves are calculated based on the U.S. Securities and Exchange Commission (SEC) requirements and may therefore differ substantially from Statoil's view on expected reserves.

Many of the factors, assumptions and variables involved in estimating reserves are beyond Statoil's control and may prove to be incorrect over time. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in Statoil's reserve data. The prices used for proved reserves are defined by the SEC and are calculated based on a 12 month un-weighted arithmetic average of the first-day-of-the-month price for each month during the reporting year, leading to a forward price strongly linked to last year's price environment. Fluctuations in oil and gas prices will have a direct impact on Statoil's proved reserves. For fields governed by production sharing agreements (PSAs), a lower price may lead to higher entitlement to the production and increased reserves for those fields. Adversely, a lower price environment may also lead to lower activity resulting in reduced reserves. For PSAs these two effects may to some degree offset each other. In addition a low price environment may result in earlier shutdown due to uneconomic production. This will affect both PSAs and fields with concession types of agreement.

Exploratory drilling involves numerous risks, including the risk that Statoil will encounter no commercially productive oil or natural gas reservoirs. This could materially adversely affect Statoil's results. Statoil's exploration activities include accessing new acreage and maturing resources through high risk exploration drilling activities. These risks include risks associated with the execution of drilling and seismic operations and those associated with maturing unproven resources.

New acreage is primarily acquired through concessions, bidding rounds and acquisitions. Geological interpretations and successful exploration drilling and appraisal work leads to maturing and commercially attractive resources. Additionally, Statoil also needs to be focused on optimising its rig capacity by thoughtful deployment and redeployment. Given these risks and operational requirements, Statoil may not effectively acquire acreage, successfully conduct its drilling and appraisal work or optimise its rig capacity, which could result in a material adverse effect on the results of its operations and financial condition. Exploration activities involve the risk of accidents and environmental incidents. Exploration activities also involve technical challenges related to operating in harsh environments as well as technologically demanding subsurface/geological challenges which Statoil may not effectively manage.

If Statoil fails to acquire or discover and develop additional reserves, its reserves and production will decline materially from their current levels.
Successful implementation of Statoil's group strategy for value growth is critically dependent on sustaining its long-term reserve replacement. If upstream resources are not progressed to proved reserves in a timely manner, Statoil's reserve base and thereby future production will gradually decline and future revenue will be reduced.

Statoil's future production is highly dependent on its success in acquiring or finding and developing additional reserves adding value. If unsuccessful, future total proved reserves and production will decline.

If the low price environment continues for a substantial time, this may result in undeveloped acreage not being considered economically viable and consequently discovered resources not being matured to reserves. This may also lead to exploration areas not being explored for new resources and subsequently not being matured for development resulting in less future proved reserves. Successful implementation of Statoil's improvement initiatives may partly offset this effect to some degree making new exploration areas and undeveloped acreage more economically attractive for exploration and development.

In a number of resource-rich countries, national oil companies control a significant proportion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies, or if Statoil is unable to develop partnerships with national oil companies, its ability to find and acquire or develop additional reserves will be more limited.

Statoil is exposed to a wide range of health, safety and environmental risks that could result in significant losses.
Exploration for, and the development, production, processing and transportation of oil and natural gas can be hazardous and technical integrity failures, operational failures, natural disasters or other occurrences can result in: loss of life, oil spills, gas leaks, loss of containment of hazardous materials, water contamination, blowouts, cratering, fires and equipment failure, among other things.

The risks associated with Statoil's activities are affected by the difficult geographies, climate zones and environmentally sensitive regions in which Statoil operates. All modes of transportation of hydrocarbons - including road, rail, sea or pipeline - are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, these could represent a significant risk to people and the environment. Offshore operations and transportation are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions. Onshore operations and transportation are subject to adverse weather conditions and accidents. Both onshore and offshore operations and transportation are subject to interruptions, restrictions or termination by government authorities based on safety, environmental or other considerations.

Policy and regulatory change due to rising climate change concerns, and the physical effects of climate change, could impact Statoil's business.
Statoil expects and is preparing for policy and regulatory changes targeted at reducing greenhouse gas emissions of its upstream operations/activities. Statoil expects greenhouse gas emission costs to increase from current levels beyond 2020 and to have a wider geographical range than today. There is continuing uncertainty over these regulatory and policy developments, including the mechanisms that will be employed, and the level of global co-ordination and hence efficiency and uniformity of measures. This in turn leads to uncertainty over the eventual long-term implications to development project cost or operating cost and constraints. As an example, new technological solutions could be required. This could result in increased cost or longer lead times, or have an impact on investment decisions for future projects. Climate related policy changes may also reduce access to prospective geographical areas in the future and affect the demand for and prices of Statoil's products.

Regulatory changes and other factors may encourage the development of low-carbon energy technologies such as renewable energy which could impact the demand for oil and gas, particularly in specific regions. As an example, development of battery technologies could allow more intermittent renewables to be used in the power sector. This could especially impact Statoil's gas sales, particularly if subsidies of renewable energy in Europe were to increase.

Statoil carefully monitors and assesses the potential impact of climate change. Developments in climate change could have a significant impact on Statoil's financial performance, profitability and outlook, whether directly through changes in taxation and regulation, or indirectly through changes in consumer behaviour.

Statoil has assessed the sensitivity of its project portfolio (equity production and expected production from accessed exploration acreage) against the assumptions regarding commodity and carbon prices in the International Energy Agency's (IEA) Current Policies scenario, the IEA New Policies scenario and the IEA 450 scenario, as laid out in their "World Economic Outlook 2015" report. The assessment demonstrated that the IEA's "450 ppm scenario", which is compatible with a global warming of maximum of two degrees Celsius with more than 50% probability, could have a negative impact of approximately 5% on Statoil's net present value compared to Statoil's internal planning assumptions as of December 2015. This assessment is based on Statoil's and the IEA's assumptions which may not be accurate and which are likely to change over time as new information becomes available. Accordingly, there can be no assurance that the assessment, which is presented in Statoil ASA's 2015 Sustainability report, is a reliable indicator of the actual impact of climate change on Statoil.

It is not possible to predict the exact magnitude of the physical impact of climate change on Statoil's operations. However, effects of climate change could result in less stable weather patterns, which would result in more severe storms and other weather conditions that could interfere with Statoil's operations. Changes in physical climate parameters could impact the costs of Statoil's operations, for example through restrained water availability and prolonged droughts, or through increasing frequency of other extreme weather events.

Statoil is exposed to risks as a result of its hydraulic fracturing usage.
Statoil's US operations use hydraulic fracturing which is subject to a range of applicable federal, state and local laws, including those discussed under the heading "Legal and Regulatory Risks". Fracturing is an important and common practice that is used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. Statoil's hydraulic fracturing and fluid handling operations are designed and operated to minimise the risk, if any, of subsurface migration of hydraulic fracturing fluids and spillage or mishandling of hydraulic fracturing fluids, however, a proven case of subsurface migration of hydraulic fracturing fluids or a case of spillage or mishandling of hydraulic fracturing fluids during these activities could potentially subject Statoil to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending on the circumstances of the underground migration, spillage, or mishandling, the nature and scope of the underground migration, spillage, or mishandling, and the applicable laws and regulations.

In addition, various states and local governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure requirements and temporary or permanent bans. New or further changes in laws and regulations imposing reporting obligations on, or otherwise banning or limiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, cause operational delays, increase costs of regulatory compliance or in exploration and production, which could adversely affect Statoil's US onshore business and the demand for fracturing services.

Statoil is exposed to security threats that could have a materially adverse effect on Statoil's results of operations and financial condition.
Although Statoil has security barriers, policies and risk management processes in places which are designed to protect its assets against a range of security threats, no assurances can be made that such attacks will not occur and adversely impact its operations. Security threats such as acts of terrorism and cyber-attacks against Statoil's production and exploration facilities, offices, pipelines, means of transportation or computer systems or breaches of Statoil's security system, could result in significant losses. Failure to manage the foregoing risks could result in injury or loss of life, damage to the environment, damage to or the destruction of wells and production facilities, pipelines and other property. Statoil could face, among other things, regulatory action, legal liability, damage to its reputation, a significant reduction in revenues, an increase in costs, a shutdown of operations and a loss of its investments in affected areas. Statoil does not purchase cyber risks insurance because the available insurance products do not provide satisfactory coverage.

Statoil's crisis management systems may prove inadequate.
Statoil has crisis management plans and capability to deal with emergencies at every level of its operations. If Statoil does not respond or is perceived not to have responded in an appropriate manner to either an external or internal crisis, its business, operations and reputation could be severely affected. For Statoil's most important activities, it has also developed business continuity plans to carry on or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed time frame could prolong the impact of any disruption and could severely affect Statoil's business and operations.

Statoil encounters competition from other oil and gas companies in all areas of its operations.
Some of Statoil's larger, financially stronger competitors may be able to pay more to gain access to resources, while its smaller competitors may be able to move faster and gain earlier access than Statoil. Gaining access to profitable resources either through the acquisition of licences, exploratory prospects or producing properties is key to ensuring the long-term health and sustainability of the business and Statoil's failure to do so could have an adverse impact on its performance.

Technology is a key competitive advantage in Statoil's industry and a larger company may be able to invest more in developing or acquiring intellectual property rights to technology that Statoil may require. Should Statoil's innovation lag behind the industry, its performance could be impeded.

Statoil's development projects and production activities involve many uncertainties and operating risks that can prevent Statoil from realising profits and cause substantial losses.
Oil and gas projects may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, irregularities in geological formations, accidents, mechanical and technical difficulties or challenges due to new technology. This is particularly relevant because of the physical environments in which some of Statoil's projects are situated. Many of Statoil's development and production projects are located in deep waters or other harsh environments - such as the Gulf of Mexico in the US, the Flemish Pass in Canada or the Barents Sea in Norway, or have challenging field characteristics such as its heavy oil projects in Brazil (Peregrino), Norway (Grane) and the UK (Mariner). In US onshore, low regional prices may cause certain areas to be unprofitable and the company may curtail production until prices recover. There is therefore a risk that Statoil undertakes development projects that do not yield expected returns, especially in the current environment of decreasing oil and gas prices combined with the relatively high levels of tax and government take in several jurisdictions, including Norway.

Capital expenditures in the oil and gas industry have increased over the last few years due to a high activity level and more complex and capital intensive development projects. This, combined with prolonged low oil and gas prices, could reduce the returns and erode the profitability of some of Statoil's projects and capital programs.

As a response to these challenges, Statoil will need at all times to evaluate profitability and robustness of projects and consider postponing or stopping projects, adjusting strategies and targets or withdrawing from certain geographical areas.

Statoil faces challenges in achieving its strategic objective of successfully exploiting profitable growth opportunities.
An important element of Statoil's strategy is to continue to pursue attractive and profitable growth opportunities available to it by both enhancing and repositioning its asset portfolio and expanding into new markets. The opportunities that Statoil is actively pursuing may involve the acquisition of businesses or properties that complement or expand its existing portfolio. The challenges related to the renewal of Statoil's upstream portfolio is growing due to increasing global competition for access to opportunities.

Statoil's ability to successfully implement this strategy will depend on a variety of factors, including its ability to:

- identify acceptable opportunities
- negotiate favourable terms
- develop new market opportunities or acquire properties or businesses promptly and profitably
- integrate acquired properties or businesses into Statoil's operations
- arrange financing, if necessary and
- comply with legal regulations

As Statoil pursues business opportunities in new and existing markets, it anticipates significant investments and costs in connection with the development of such opportunities. Statoil may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Any failure by Statoil to successfully pursue and exploit new business opportunities could result in financial losses and inhibit growth. Any such new projects Statoil acquires will require additional capital expenditure and will increase the cost of its discoveries and development. These projects may also have different risk profiles than Statoil's existing portfolio. These and other effects of such acquisitions could result in Statoil having to revise either or both of Statoil's forecasts with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from Statoil's day-to-day operations to the integration of acquired operations or properties. Statoil may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to Statoil, if at all, and it may, in the case of equity, be dilutive to Statoil's earnings per share.

The profitability of Statoil's oil and gas production may be affected by limited transportation infrastructure when a field is in a remote location.
Statoil's ability to exploit economically any discovered petroleum resources beyond its proved reserves will depend, among other factors, on the availability of the infrastructure required to transport oil and gas to potential buyers at a commercially acceptable price. Oil is transported by vessels, rail or pipelines to refineries, and natural gas is usually transported by pipeline or by vessels (for liquid natural gas) to processing plants and end users. Statoil may not be successful in its efforts to secure transportation and markets for all of its potential production.

Statoil is exposed to security threats on its information systems and digital infrastructure that could harm its assets and operations.
Statoil's security barriers protect its information systems and digital infrastructure from being compromised by unauthorised parties. Failure to maintain and develop these barriers may affect the confidentiality, integrity and availability of its information systems and digital infrastructure, including those critical to Statoil's operations. Threats to Statoil's information systems could result in significant financial damage to Statoil. Threats to Statoil's industrial control systems are not limited by geography as Statoil's digital infrastructure is accessible globally, and incidents in the industry in recent years have shown that parties who are able to circumvent barriers aimed at securing industrial control systems are capable and willing to perform attacks that destroy, disrupt or otherwise compromise operations. Such attacks could result in material losses or loss of life with consequent financial implications.

Some of Statoil's international interests are located in regions where political, social and economic instability could adversely impact Statoil's business.
Statoil has assets and operations located in politically, socially and economically diverse regions around the world where potential developments such as expropriation, nationalisation of property, unilateral change of contracts or regulations, civil strife, strikes, political unrest, war, terrorism, border disputes, guerrilla activities, insurrections, piracy and the imposition of international sanctions or other events could occur. Political risks and security threats require continuous monitoring. Adverse and hostile actions against Statoil's staff, its facilities, its transportation systems and its digital infrastructure (cybersecurity) could cause harm to people and disrupt Statoil's operations and further business opportunities in these or other regions, lead to a decline in production and otherwise adversely affect Statoil's business. This could have a materially adverse effect on Statoil's results of operations and its financial condition.

Statoil's operations are subject to dynamic political and legal factors in the countries in which it operates.
Statoil has assets in a number of countries with emerging or transitioning economies that, in part or in whole, lack well-functioning and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Statoil's exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and impose more stringent conditions on companies engaged in exploration and production activities. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports
- the awarding or denial of exploration and production interests
- the imposition of specific seismic and/or drilling obligations
- price and exchange controls
- tax or royalty increases, including retroactive claims
- nationalisation or expropriation of Statoil's assets
- unilateral cancellation or modification of Statoil's licence or contractual rights
- the renegotiation of contracts
- payment delays and
- currency exchange restrictions or currency devaluation

The likelihood of these occurrences and their overall effect on Statoil vary greatly from country to country and are hard to predict. If such risks materialise, they could cause Statoil to incur material costs and/or cause Statoil's production to decrease, potentially having a materially adverse effect on Statoil's operations or financial condition.

Statoil is exposed to potentially adverse changes in the tax regimes of each jurisdiction in which Statoil operates.
Statoil has business operations in many countries around the world. Changes in the tax laws of the countries in which Statoil operates could have a material adverse effect on its liquidity and results of operations.

Statoil faces foreign exchange risks that could adversely affect the results of Statoil's operations.
Statoil's business faces foreign exchange risks and this is managed with USD as the base currency. Statoil has a large percentage of its revenues and cash receipts denominated in USD and sales of gas and refined products are mainly denominated in EUR and GBP. Further, Statoil pays a large portion of its income taxes, and a share of our operating expenses and capital expenditures, in NOK. The majority of Statoil's long term debt has USD exposure.

Statoil is exposed to risks relating to trading and supply activities.
Statoil is engaged in substantial trading and commercial activities in the physical markets. Statoil also uses financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. Statoil also uses financial instruments to manage foreign exchange and interest rate risk. Although Statoil believes it has established appropriate risk management procedures, trading activities involve elements of forecasting, and Statoil bears the risk of market movements, the risk of losses if prices develop contrary to expectations, and the risk of default by counterparties.

Non-compliance with anti-bribery, anti-corruption and other applicable laws, including failure to meet Statoil's ethical requirements, exposes Statoil to legal liability and damage to its reputation, business and shareholder value.
Statoil has activities in countries which present corruption risks and which may have weak legal institutions, lack of control and transparency. In addition, governments play a significant role in the oil and gas sector, through ownership of resources, participation, licensing and local content which leads to a high level of interaction with public officials. Statoil is, through its international activities, subject to anti-corruption and bribery laws in multiple jurisdictions, including the Norwegian Penal code, the US Foreign Corrupt Practices Act and the UK Bribery Act. A violation of any applicable anti-corruption and bribery laws could expose Statoil to investigations from multiple authorities, and any violations of laws may lead to criminal and/or civil liability with substantial fines. Incidents of non-compliance with applicable anti-corruption and bribery laws and regulations and the Statoil Code of Conduct could be damaging to Statoil's reputation, competitiveness and shareholder value.

Statoil's insurance coverage may not provide adequate protection.
Statoil maintains insurance coverage that includes coverage for physical damage to its oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. Statoil's insurance coverage includes deductibles that must be met prior to recovery. Statoil's external insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect Statoil against liability from all potential consequences and damages.

Statoil's efficiency change agenda may impact the development of Statoil's business and its financial results.
In 2014, Statoil announced an extensive efficiency change strategy in order to improve efficiency across the organisation in light of the decline in oil and gas prices. Two programmes were launched, the Statoil Technical Efficiency Programme (STEP) and the organisational efficiency programme (OE). There is a risk of Statoil not being able to define and implement the activities related to cost savings without adversely effecting Statoil's business goals or achieving the necessary cost savings and increases in efficiency

Statoil may fail to secure the right level of workforce competence and capacity over the short and medium term
The external uncertainty of the future of the oil industry in light of reduced oil and natural gas prices and climate policy changes, creates a risk in ensuring a robust workforce through industry cycles. The oil industry is a long term business and needs to take a long term perspective on workforce capacity and competence. Given the current extensive change agenda there is a risk that Statoil will fail to secure the right level of workforce competence and capacity.

Statoil's activities in certain countries may be affected by international sanctions.
Statoil, like other major international energy companies, has a geographically diverse portfolio of reserves and operational sites, which may expose its business and financial affairs to political and economic risks, including operations in areas subject to international sanctions or with sanctioned entities.

Russia
Statoil holds a 30% non-operating interest in a production sharing agreement related to the Kharyaga field in the Nenets Autonomous Area in the Russian Federation. The Kharyaga field produces conventional oil from the Timan Pechora basin onshore in North West Russia. Statoil is further engaged in a

strategic cooperation with Rosneft Oil Company (Rosneft) including a joint cooperation project aimed at undertaking seismic surveys and geological exploration, appraisal, development and production of potential hydrocarbons in four licences on the Russian continental shelf - the Magadan 1, Lisyansky and Kashevarovsky licences in the Sea of Okhotsk (south of the Arctic Circle), and the Perseevsky licence in the Barents Sea (north of the Arctic Circle). Additionally there are two joint cooperation projects onshore; pilot drilling and testing of the onshore heavy oil reservoir layer PK1 in the North Komsomolsky discovery, and the Domanik Sediments Difficult-to-Extract Hydrocarbons Project, aimed at pilot drilling and testing of the limestone Domanik formation in the Russian Volga-Urals basin. For each of these projects, Rosneft holds the majority interest, while Statoil holds a minority interest.

Sanctions imposed by Norway, the EU and the USA target, among others, Russia's financial and energy sectors, including certain companies such as Rosneft and various affiliates, and specific activities related to oil exploration and production in the Arctic offshore area, and in deepwater or shale formation projects. Aspects of those measures affect Statoil's business activities in Russia. The continued progress and financing of the joint projects are, in part, dependent on Statoil and the joint ventures securing various governmental authorisations and clarifications from such governmental authorities also going forward. Statoil continues to pursue the above-described projects within the limitations of current sanctions. However, due to current and possible future sanctions, there is no certainty that the projects can be progressed and concluded as initially planned.

Iran

Certain countries, including Iran, have been identified by the US government as state sponsors of terrorism.

Historically, Statoil held interests in the Iranian South Pars offshore phase 6, 7 and 8 gas development project in the Persian Gulf. Statoil was also an owner of a significant interest in the Anaran block and held a 100% interest in the Khorramabad exploration block - both in Iran. Due to the increase of international sanctions against Iran, Statoil in 2009 voluntarily offered officials from the US State Department information about its Iranian business activity. In October 2010 the US State Department announced under the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA), Statoil to be eligible to avoid retaliatory measures relating to its activities in Iran, due to Statoil's pledge to end its investments in Iran's energy sector.

Following the January 2016 sanctions relief, offered Iran by the US in accordance with the Joint Comprehensive Plan of Action entered into by Iran and the P5+1, secondary US nuclear sanctions on Iran have been scaled back. Despite this, other secondary and primary US sanctions on Iran remain in place. Since 2010, Statoil's activities relating to Iran have consisted of closing its historic projects in an orderly and compliant manner consistent with applicable sanctions. This has also included efforts to settle, to the extent possible, outstanding tax and social security obligations and recovery rights related to the above mentioned projects. Statoil has at regular intervals kept both relevant Norwegian as well as US authorities updated of such continued efforts.

A company found to have violated US sanctions against Iran could become subject to various types of sanctions, including (but not limited to) denial of US bank loans, restrictions on the importation of goods produced by the sanctioned entity, the prohibition on property transactions by the sanctioned entity in which the property is subject to the jurisdiction of the United States and prohibition of transfers of credit or payments via financial institutions in which the sanctioned entity has any interest.

General

The legislation and rules governing sanctions are complex, constantly evolving and may not be consistent across jurisdictions. Changes in any of these laws or policies or the implementation thereof can be unpredictable. Statoil's business is dynamic and the above facts accordingly, may change over time. Moreover, the description does not fully reflect all parts of Statoil's business where a particular focus on sanctions compliance might be warranted. Lastly, it should be understood that Statoil in the future could also decide to take part in additional business activity also involving sanctioned targets in various parts of the world whilst still remaining compliant with applicable sanctions laws. Statoil is committed to doing business in compliance with all applicable laws, however there can be no assurance that Statoil or affiliates of Statoil or their respective officers, directors, employees or agents are not in violation of such laws. Any such violation could result in substantial civil and/or criminal penalties and might materially adversely affect Statoil's business and results of operations or financial condition.

Statoil is also aware of initiatives by certain US states and institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring, among other things, divestment from, reporting of interests in, or agreements not to make future investments in, companies that do business with countries that, among other things, are designated as state sponsors of terrorism. These policies could have an adverse impact on investments by certain investors in Statoil's securities.

Disclosure Pursuant to Section 13 (r) of the Exchange Act

The Iran Threat Reduction and Syria Human Rights Act of 2012 ("ITRA") created a new subsection (r) in Section 13 of the Exchange Act which requires a reporting issuer to provide disclosure if the issuer or any of its affiliates engaged in certain enumerated activities relating to Iran, including activities involving the Government of Iran. Statoil is providing the following disclosure pursuant to Section 13(r).

Statoil is a party to agreements with the National Iranian Oil Company (NIOC), namely, a Development Service Contract for South Pars Gas Phases 6, 7 & 8 (offshore part), an Exploration Service Contract for the Anaran Block and an Exploration Service Contract for the Khorramabad Block, which are located in Iran. Statoil's operational obligations under these agreements have terminated and the licenses have been abandoned.

The cost recovery program for these contracts was completed in 2012, except for the recovery of tax and obligations to the Social Security organisation (SSO). Statoil's activity in Iran during 2015 was focused on a final settlement with the Iranian tax authorities and the SSO relating to the above mentioned agreements. During 2015 Statoil paid the equivalent of USD 3.20 million in tax and SSO to Iranian authorities in local currency (Iranian Rials), from which USD 0.04 million has been booked as expenses in 2015 and the rest have been reversed from previous years' accruals. Also during 2015 Statoil paid USD 0.02 million stamp duty to Iran Tax Organisation. The funds utilised for these purposes were held by Statoil in EN Bank (Iran).

During 2015 Statoil also received the equivalent of USD 0.48 million as insurance payment related to its legacy South Pars business. Also this insurance payment has been booked as revenue in 2015.

During 2015 NIOC, on behalf of Statoil, paid a tax obligation of USD 1.6 million equivalent in Iranian Rial to the local tax authorities. The amount was settled towards recoverable costs from NIOC to Statoil. Statoil is not involved in any other activities in Iran.

Since 2009 Statoil has transparently and regularly provided information about its Iran related activity to the US State Department as well as to the Norwegian Ministry of Foreign Affairs. In a letter from the US State Department of 1November 2010, Statoil was informed that the company was not considered to be a company of concern based on its previous Iran-related activities.

Statoil generated no net profit from the aforementioned activity in 2015. Payments of the above mentioned nature are expected to be made also in 2016, in relation to Statoil's continued winding-down efforts.

In addition, Statoil has in the course of 2015 paid four annual patent fees in Iran of in total EUR 347 (appr. USD 420). The payment of these patent fees will be discontinued in 2016.

5.1.2 Legal and regulatory risks

This section discusses potential legal and regulatory risks related to the legal context of our business operations, such as having to comply with new laws and regulations.

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase its costs. The enactment of such laws and regulations in the future is uncertain.

Statoil incurs, and expects to continue to incur, substantial capital, operating, maintenance and remediation costs relating to compliance with increasingly complex laws and regulations for the protection of the environment and human health and safety, including:

- costs as a result of stricter climate regulations and a higher price on greenhouse gas emissions
- costs of preventing, controlling, eliminating or reducing certain types of emissions to air and discharges to the sea, including costs incurred in connection with government action to address the risk of spills and concerns about the impacts of climate change
- remediation of environmental contamination and adverse impacts caused by Statoil's activities or accidents at various facilities owned or previously owned by Statoil and at third-party sites where Statoil's products or waste have been handled or disposed of
- compensation of persons and/or entities claiming damages as a result of Statoil's activities or accidents and
- costs in connection with the decommissioning of drilling platforms and other facilities

For example, under the Norwegian Petroleum Act of 29 November 1996, as a holder of licences on the Norwegian continental shelf (NCS), Statoil is subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of Statoil's licences. This means that anyone within the state or the delineation of the NCS who suffers losses or damage as a result of pollution caused by operations in any of Statoil's NCS licence areas can claim compensation from Statoil without having to demonstrate that the damage is due to any fault on Statoil's part.

Furthermore, in countries where Statoil operates or expects to operate in the near future, new laws and regulations, the imposition of stricter requirements on licences, increasingly strict enforcement of or new interpretations of existing laws and regulations, the aftermath of operational catastrophes in which Statoil or members of its industry are involved or the discovery of previously unknown contamination may require future expenditure in order to, among other things:

- modify operations
- install pollution control equipment
- implement additional safety measures
- perform site clean-ups
- curtail or cease certain operations
- temporarily shut down Statoil's facilities
- meet technical requirements
- increase monitoring, training, record-keeping and contingency planning and
- establish credentials in order to be permitted to commence drilling

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability as a result of changes in operating costs, and adverse effects on revenue generation and strategic growth opportunities. Statoil regularly assesses how changes in regulations, including introduction of stringent climate policies, may impact the oil price, the costs of developing new oil and gas assets, and the demand for oil and gas.

Statoil's operations in Norway are subject to emissions taxes as well as emissions allowances granted for Statoil's larger European operations under the EU Emissions Trading System. The agreed strengthening of the European Union's emission trading scheme may result in a significant reduction in the total emissions from relevant energy and industry installations which includes Statoil's installations at the NCS. The price of the emissions allowances is also expected to increase significantly towards 2030. At the 21st Conference of Parties (COP21) in Paris in December 2015, 195 countries adopted a new universally applicable climate agreement, to be effective from 2020. The Norwegian Parliament decided that Norway should negotiate with the European

Union to develop the terms for a collective delivery of 40% reductions in greenhouse gas emissions by 2030 compared to 1990. Individual countries' climate plans, the so-called 'Intended Nationally Determined Contributions', are to be strengthened every five years. The implications for the industry are not yet clear, however requirements to reduce emissions could imply increased costs.

The EU Fuel Quality Directive 2009/30/EC and its Implementation Directive 2015/652/EU require fuel suppliers to reduce their carbon intensity for transportation fuels by 6% in 2020 compared to the baseline of 2010. Fuel suppliers can use biofuels, low carbon fuels (i.e. natural gas), charging of electric vehicles and upstream emission reductions to achieve the target. Member States may set penalties on fuels suppliers for not achieving the target. The EU Commission will submit a non-legislative guidance document before April 2017 which will propose common principles on verification and accounting of upstream emissions reductions. The regulation could indirectly impact Statoil if it results in incentives for service station companies to increase the share of biofuels on behalf of fossil fuels.

In the US, the Environmental Protection Agency has taken steps to regulate greenhouse gas emissions under the *Clean Air Act* authority by proposing a Clean Power Plan (CPP). The plan aims to reduce emissions from the US power sector by setting performance standards for power plants. The regulation, if approved, could stimulate increased gas demand. In 2015, the EPA also proposed new source performance standards, in addition to those issued in 2012, targeting volatile organic compound emissions, that are intended to further reduce oil and gas methane emissions. This could imply additional costs for oil and gas producers.

Statoil incorporates a cost for carbon in the assessment of all new projects. This guides Statoil's strategy and its investment decisions. For investment decisions pertaining to oil and gas projects in Norway, Statoil includes an internal cost of USD 64 per tonne of CO_2-equivalent (based on the average annual exchange rate in 2015), based on the cost of the Norwegian CO_2 tax. In 2014, Statoil began to apply an internal cost of USD 50 per tonne of CO_2-equivalent in its investment decisions for all new oil and gas projects outside of Norway.

Many of Statoil's mature fields are producing increasing quantities of water with oil and gas. Statoil's ability to dispose of this water in environmentally acceptable ways may have an impact on its oil and gas production. Statoil's investments in North American onshore producing assets will be subject to evolving regulations which are common to all energy companies with investments in this region. This could affect Statoil's operations and profitability with respect to these operations.

If Statoil does not succeed in overcoming the perceived trade-off between global access to energy and the protection or improvement of the natural environment, Statoil could fail to live up to its aspirations of zero or minimal damage to the environment and of contributing to human progress.

Statoil is exposed to risk of supervision, review and sanctions for violations of regulatory laws at the supranational and national level. These include, among others, competition and antitrust laws and financial and trading.
Statoil's products are marketed and traded worldwide and therefore subject to competition and antitrust laws at the supranational and national level in multiple jurisdictions. Statoil is exposed to investigations from competition and antitrust authorities, and violations of the applicable laws and regulations may lead to substantial fines. In December 2015, the European Commission announced that it currently will not pursue its investigation against Statoil and certain other oil and gas producers concerning alleged crude oil price manipulation. The investigation had been on-going since May 2013 when the EFTA Surveillance Authority conducted an unannounced inspection at Statoil's head office in Stavanger, Norway, on behalf of the European Commission. The authorities suspected participation by several companies, including Statoil, in anti-competitive practices and/or market manipulation related to Platts Market-On-Close price assessment process.

Statoil is also exposed to financial review from financial supervisory authorities such as the Norwegian Financial Supervisory Authority (FSA) and the US Securities and Exchange Commission (the SEC). Reviews performed by these authorities could result in changes to previous accounts and future accounting policies. On 10 March 2014, the FSA concluded a review of Statoil's 2012 financial statements. Statoil has accepted two of the FSA's conclusions following this review but has appealed the third to the Norwegian Ministry of Finance.

Statoil is listed on both the Oslo Børs and New York Stock Exchange (NYSE), and is registered with the SEC. Statoil is required to comply with the continuing obligations of these regulatory authorities, and violation of these obligations may result in imposition of fines or other sanctions.

The Norwegian Petroleum Supervisor (Ptil) supervises all aspects of Statoil's operations, from exploration drilling through development and operation, to cessation and removal. Its regulatory authority covers the whole NCS as well as petroleum-related plants on land in Norway. Statoil is exposed to supervision from Ptil, and such supervision could result in audit reports, orders and investigations.

The formation of a competitive internal gas market within the European Union (EU) and the general liberalisation of European gas markets could adversely affect Statoil's business.
The continuing liberalisation of EU gas markets following legislative instruments rolled out in 2011 and the implementation of these legislative instruments by member states, could create new business opportunities for Statoil, but could also affect Statoil's market position or result in a reduction in prices in Statoil's gas sales contracts. Statoil's exposure to hub gas prices has increased and correspondingly increased Statoil's exposure to price volatility. Statoil continually monitors its contractual obligations and makes efforts to negotiate the most competitive pricing and other conditions available in the market.

The EU-wide quantity of carbon allowances issued each year under the Emission Trading Scheme (ETS) for greenhouse gas emission allowances began to decrease in a linear manner in 2013. The ETS can have a positive or negative impact on Statoil, depending on the price of carbon, which will consequently have an impact on the development of gas-fired power generation in the EU. Until now, the carbon price has been too low to replace coal with gas fired generation capacity. This effect has been worsened by heavy subsidising of renewables which has caused gas fired power plants to shut down. Current EU climate and energy policies do not address this problem, but there is a tendency towards more market based subsidies in the new guidelines on environment and energy aid.

Political and economic policies of the Norwegian State could affect Statoil's business.
The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the State's direct financial interest (SDFI) and its indirect impact through legislation, such as tax and environmental laws and regulations, the Norwegian State, among other things, awards licences for exploration, production and transportation, approves exploration and development projects and applications for production rates for individual fields and may, if important public interests are at stake, also instruct Statoil and other oil companies to reduce petroleum production. Furthermore, in the production licences in which the SDFI holds an interest, the Norwegian State has the power to direct petroleum licences' actions in certain circumstances.

If the Norwegian State were to take additional action under its activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, Statoil's NCS exploration, development and production activities and the results of its operations could be affected.

5.1.3 Risks related to state ownership

This section discusses some of the potential risks relating to Statoil's business that could derive from the Norwegian State's majority ownership and from Statoil's involvement in the SDFI.

The interests of Statoil's majority shareholder, the Norwegian State, may not always be aligned with the interests of Statoil's other shareholders, and this may affect Statoil's decisions relating to the NCS.
The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in Statoil and the SDFI's interest in NCS licences must be managed in accordance with a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required Statoil to continue to market the Norwegian State's oil and gas together with Statoil's own oil and gas as a single economic unit.

Pursuant to this coordinated ownership strategy, the Norwegian State requires Statoil, in its activities on the NCS, to take account of the Norwegian State's interests in all decisions that may affect the development and marketing of Statoil's own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of Statoil's ordinary shares as of 31 December 2015. Based on the Norwegian Public Limited Companies Act, the Norwegian State effectively has the power to influence the outcome of any vote of shareholders due to the percentage of Statoil's shares it owns, including amending its articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one-third of the corporate assembly.

The corporate assembly is responsible for electing Statoil's board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profit and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers when casting its votes, especially under the coordinated ownership strategy for the SDFI and Statoil's shares held by the Norwegian State, could be different from the interests of Statoil's other shareholders.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then Statoil's mandate to continue to sell the Norwegian State's oil and gas together with its own oil and gas as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on Statoil's position in the markets in which it operates.

For further information about the mandate to sell the Norwegian State's oil and gas see section 3.12.4 *SDFI oil and gas marketing and sale.*

5.2 Risk management

Statoil's overall risk management approach includes identifying, evaluating and managing risk in all its activities. In order to achieve optimal corporate solutions, Statoil bases its risk management on an enterprise-wide risk management approach.

Statoil defines risk as a deviation from a specified reference value and the uncertainty associated with it. A positive deviation is defined as an upside risk, while a negative deviation is a downside risk. The reference value is most commonly a forecast, percentile or target. Statoil has an enterprise risk management (ERM) approach, which means that:

- focus is on the value impact for Statoil
- risk is managed to make sure that Statoil's operations are safe and in compliance with Statoils' requirements and
- focus is on risk and reward at all levels in the organisation

Statoil's corporate risk committee (CRC) is headed by the chief financial officer and its members include representatives of the principal business areas. It is an enterprise risk management advisory body that primarily advises the chief financial officer, but also the business areas' management on specific issues. The CRC assesses and advises on measures aimed at managing the overall risk to the group, and it proposes appropriate measures to adjust risk at the corporate level. The CRC is also responsible for reviewing and developing Statoil's risk policies. The committee meets regularly during the year to support Statoil's risk management strategies, including hedging and trading strategies, as well as risk management methodologies. It regularly receives risk information that is relevant to it from Statoil's corporate risk department.

Risk is managed in the business line and is an integrated part of any manager's responsibility. However, some risks are managed at corporate level to avoid suboptimisation. This includes oil and natural gas price risks, interest and currency risks, risk dimension in the strategy work, prioritisation processes and capital structure discussions.

The following section describes in some detail the market risks to which Statoil is exposed and how Statoil manages these risks.

5.2.1 Managing operational risk

Statoil manages risk in order to ensure safe operations and to achieve its corporate goals in compliance with its requirements.

All risks are related to Statoil's value chain, which denotes the value that is added in each step - from access, maturing, project execution and operation to market. In addition to the economic impact these risks could have on Statoil's cash flows, Statoil has have a strong focus on avoiding HSE and integrity-related incidents (such as accidents, fraud and corruption). Most of the risks are managed by the principal business area line managers. Some operational risks are insurable and insured by Statoil's captive insurance company operating in the Norwegian and international insurance markets.

Statoil's risk management process is based on ISO31000 Risk management - principles and guidelines. The process provides a standardised framework and methodology for assessing and managing risk. A standardisation of the process across the entire enterprise allows for comparable risk levels and efficiency in decisions and it enables the organisation to create sustainable value while avoiding incidents. The process ensures that risks are identified, analysed, evaluated and managed. Risk adjusting actions are subject to a cost benefit evaluation (except certain safety related risks which are subject to specific regulations).

5.2.2 Managing financial risk

The results of Statoil's operations depend on a number of factors, most significantly those that affect the price it receives for the products.

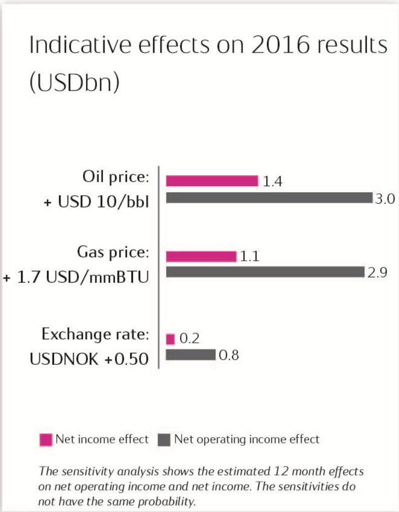
Statoil has developed policies aimed at managing the financial volatility inherent in some of the business exposures. In accordance with these policies, Statoil enters into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the company level, the business areas are responsible for marketing and trading commodities are also responsible for managing commodity-based price risks. Interest, liquidity, liability and credit risks are managed by the company's central finance department.

The factors that influence the results of Statoil's operations include: the level of crude oil and natural gas prices, trends in the exchange rate between the USD, in which the trading price of crude oil is generally stated, EUR and GBP where Statoil has a large share of its natural gas sales, and NOK, in which its accounts are reported and a substantial proportion of the costs are incurred; Statoil's oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and Statoil's own, as well as partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in Statoil's portfolio of assets due to acquisitions and disposals.

Statoil's results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which Statoil operates, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (Opec) and/or other producing nations that affect price levels and volumes, refining margins, the cost of oilfield services, supplies and equipment, competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, all of which may cause substantial changes to existing market structures and to the overall level and volatility of prices and price differentials.

The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas average sales prices, refining reference margins and the USDNOK exchange rates for 2015, 2014 and 2013.

Yearly average	2015	2014	2013
Crude oil (USD/bbl Brent blend)	55.3	98.9	108.7
Average invoiced gas prices - Europe (NOK/scm)	2.16	2.28	2.45
Refining reference margin (USD/bbl)	8.0	4.7	4.1
USDNOK average daily exchange rate	8.07	6.30	5.88



The illustration shows the indicative full-year effect on the financial result for 2016 given certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate. The estimated price sensitivity of Statoil's financial results to each of the factors has been estimated based on the assumption that all other factors remain unchanged.

Significant downward adjustments of Statoil's commodity price assumptions will result in impairment losses on certain producing and development assets in the portfolio. Subsequent to year end 2015, commodity prices have continued to be volatile. See note 11 *Property, plant and equipment* and note 12 *Intangible assets* to the Consolidated financial statements for sensitivity analysis related to impairment losses.

Statoil assesses oil and gas price hedging opportunities on a regular basis as a tool with regard to financial robustness and flexibility.

Fluctuating foreign exchange rates can have a significant impact on the operating results. Statoil's revenues and cash flows are mainly denominated in or driven by USD, while a large portion of the operating expenses, capital expenditures and income taxes payable accrue in NOK. Statoil seeks to manage this currency mismatch by issuing or swapping non-current financial debt in USD. This long-term funding policy is an integrated part of our total risk management programme. Statoil also engages in foreign currency management in order to cover the non-USD needs, which are primarily in NOK. In general, an increase in the value of USD in relation to NOK can be expected to increase Statoil's reported earnings.

Historically, Statoil's revenues have largely been generated by the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities (a symmetrical tax system). For more information see section 3.12.6 *Taxation of Statoil.*

Statoil's earnings volatility is moderated as a result of the significant proportion of its Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by its Norwegian offshore operations in any loss-making periods. Most of the taxes Statoil pays are paid to the Norwegian State. Dividends received in Norway are 97% exempt from tax, with the remaining 3% taxed at the ordinary rate of 27%. For dividends received from companies in a low-tax jurisdiction within the European Economic Area (EEA), the 97% exemption only applies if real business activities are conducted in that jurisdiction. Dividends received from companies in non-EEA countries are 97% exempt if the Norwegian recipient has held at least 10% of the shares for a minimum of two years and the foreign country is not a low-tax jurisdiction.

Government fiscal policy is an issue in several of the countries in which Statoil operates, such as, but not limited to, Algeria, Angola, Nigeria, Brazil, the USA and Venezuela. However, Statoil's exposure in Venezuela is low. For instance, government fiscal policy could require royalties in cash or in kind, increased tax rates, increased government participation and changes in terms and conditions as defined in various production or income-sharing contracts. Statoil's financial statements are based on currently enacted regulations and on any current claims from tax authorities regarding past events. Developments in government fiscal policy may have a negative effect on future net income.

Financial risk management

Statoil's business activities naturally expose the group to financial risk. The group's approach to risk management includes identifying, evaluating and managing risk in all activities using a top-down approach for the purpose of avoiding sub-optimisation and utilising correlations observed from a group perspective. Summing up the different market risks without including the correlations will overestimate Statoil's total market risk. For this reason, Statoil utilises correlations between all of the most important market risks, such as oil and natural gas prices, product prices, currencies and interest rates, to calculate the overall market risk and thereby utilise the natural hedges embedded in its portfolio. This approach also reduces the number of unnecessary transactions, which reduces transaction costs and avoids sub-optimisation.

In order to achieve the above effects, Statoil has centralised trading mandates (financial positions taken to achieve financial gains, in addition to established policies) so that all major/strategic transactions are coordinated through the CRC. Local trading mandates are therefore relatively small.

Statoil's activities expose the company to the following financial risks: market risks (including commodity price risk, interest rate risk and currency risk), liquidity risk and credit risk. For a discussion of financial risk management see note 5 *Financial risk management* in the Consolidated financial statements.

5.2.3 Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk* in the Consolidated financial statements, for details of the nature and extent of such positions, and for qualitative and quantitative disclosures of the risks associated with these instruments.

5.3 Legal proceedings

Statoil is involved in a number of proceedings globally concerning matters arising in connection with the conduct of its business.

Statoil is currently not aware of any regulatory, judicial or arbitration proceedings or claims that it believes may have, or have had in the recent past, individually or in the aggregate, significant effects on Statoil's financial position or profitability or on the results of its operations or liquidity. This includes the legal proceedings described hereafter:

Agbami redetermination, Nigeria:
Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015 Statoil received the expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field from 20.21% to 15.04%. In 2013, Statoil initiated arbitration proceedings to set aside interim decisions made by the expert in the redetermination process, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has initiated proceedings before the Federal High Court in Lagos to set aside the arbitration award, and also intends to initiate a new arbitration to set aside the expert's final ruling.

As of 31 December 2015 Statoil has made a provision of NOK 9.5 billion, net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field.

Royalty Litigation, US Onshore:
Statoil is currently defending multiple, but individually immaterial, royalty litigations and arbitrations, some on behalf of large classes of mineral owners, relating to its operated and non-operated positions in the Marcellus and Eagle Ford shale plays. Mineral owners in these proceedings generally allege that Statoil has breached their oil and gas leases by first paying royalty on the basis of an impermissibly-low unit price, and second taking prohibited and/or excessive deductions for post-production costs. The cases are in various procedural stages and are typical disputes for oil companies in the US onshore business. None of the litigations or arbitrations is currently set for trial or final hearing.

In the ordinary course of business, companies in the Statoil group are subject to a number of other loss contingencies arising from litigation and claims raised by governmental and private parties, for instance contractors, tax authorities, land owners for on-shore activities and buyers of Statoil's products.

See also note 9 *Income taxes* and note 23 *Other commitments and contingencies* in Consolidated financial statements.

6 Shareholder information

Statoil is the largest company listed on the Oslo Børs, where it trades under the ticker code STL. Statoil is also listed on the New York Stock Exchange under the ticker code STO.

STATOIL SHARE	2015	2014	2013	2012	2011
Shareprice STL (low) (NOK)	116.30	120.00	147.70	162.40	160.50
Shareprice STL (average) (NOK)	137.59	166.41	123.00	133.80	113.70
Shareprice STL (high) (NOK)	160.80	194.80	136.72	146.97	139.60
Shareprice STL (year-end) (NOK)	123.70	131.20	147.00	139.00	153.50
Market value year-end (NOK billion)	394	418	468	443	490
Daily turnover (million shares)	5.1	3.7	3.0	4.3	8.9
Ordinary earnings per share (EPS) (NOK)	-11.80	6.87	12.50	21.60	24.70
P/E[1]	-10.48	19.10	11.76	6.44	6.21
Ordinary dividend per share (NOK)[2]	1.80	7.20	7.00	6.75	6.50
Ordinary dividend per share (USD)[2]	0.6603				
Growth in ordinary dividend per share[3]	NA	2.9%	3.7%	3.8%	4.0%
Dividend per share (NOK)[4]	7.62	7.20	7.00	6.75	6.50
Dividend per share (USD)[4]	0.86	0.97	1.15	1.21	1.08
Pay-out ratio[5]	-65%	105%	56%	31%	26%
Dividend yield[6]	6.2%	5.5%	4.8%	4.9%	4.2%
Ordinary shares outstanding, weighted average	3,179,442,977	3,179,958,780	3,180,683,828	3,181,546,060	3,182,112,843
Ordinary shares outstanding, year-end	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103

1) Share price at year end divided by EPS.

2) Proposed cash dividend for 2015. For 2015, the NOK amount covers first quarter while the USD amount is for second, third and fourth quarter. See section 6.1 *Dividend policy*.

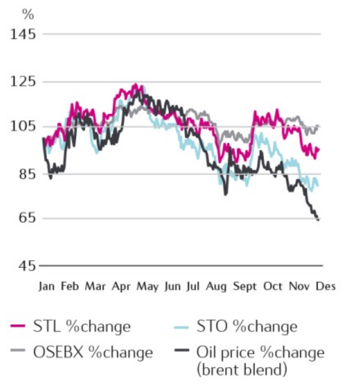
3) Excluding special dividend and share buy-back.

4) Conversions between NOK and USD are conducted by applying the year end exchange rate for the respective year.

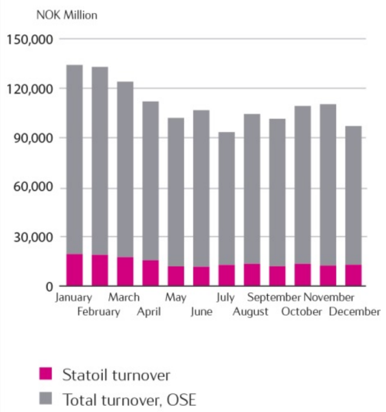
5) Total dividend per share in NOK divided by EPS.

6) Total dividend per share in NOK divided by year end share price.

Quote history



Turnover



As of 31 December 2015, Statoil represented 14.68% of the total value of all companies registered on the Oslo Børs, with a market value of NOK 394 billion.

Statoil's share price closed at NOK 123.70 at the end of 2015.

Taking into consideration the total dividend paid out in 2015 of NOK 7.20 per share, which includes four quarterly payments of NOK 1.80 per share for the third and fourth quarter of 2014 and first and second quarter of 2015, the total return was negative NOK 0.30 per share. The graph above, "Quote history", shows the development of the Statoil share price compared to the oil price and the Oslo Børs Benchmark Index (OSEBX). The board of directors proposes a dividend of USD 0.2201 per share for the fourth quarter 2015, for approval by the annual general meeting on 11 May 2016. Diluted earnings per share amounted to negative NOK 11.80, compared to positive NOK 6.87 in 2014.

The turnover of shares is a measure of traded volumes. On average, 5.1 million Statoil shares were traded on the Oslo Børs every day in 2015 compared to 3.7 million shares in 2014. In 2015, Statoil shares accounted for 15% of the total market value traded throughout the year (see illustration), compared to 12% in 2014.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,188,647,103 ordinary shares outstanding at year end.

As of 31 December 2015, Statoil had 91,774 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 92,692 shareholders at 31 December 2014.

6.1 Dividend policy

It is Statoil's ambition to grow the annual cash dividend measured in USD per share in line with long-term underlying earnings.

Statoil's board approves first, second and third quarter interim dividends, based on an authorisation from the annual general meeting (AGM), while the AGM approves the fourth quarter dividend and the implicit the total dividend based on a proposal from the board. When deciding the interim dividends and recommending the total annual dividend level, the board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders. The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter dividend proposed by the board of directors. It is Statoil's intention to have this authorisation approved at the AGM. Statoil announces dividend payments in connection with quarterly results. Payment of quarterly dividends is expected to take place approximately four months after the announcement of each quarterly dividend.

The board of directors updated the dividend policy in 2015 to reflect USD as the declaration currency.

The board of directors proposes to the AGM a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme for eligible shareholders starting from the fourth quarter 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil at a 5% discount for the fourth quarter 2015. The Norwegian Government, as majority shareholder, supports the proposal and will seek the Norwegian Parliament's approval to vote in favour of the proposal at the AGM. The Norwegian government intends to match subscription of shares by minority shareholders, and thereby maintain its ownership share at 67% throughout the programme.

6.1.1 Dividends

In 2014 Statoil implemented quarterly dividend payments and from second quarter 2015 Statoil implemented USD as dividend declaration currency.

Although we currently intend to pay quarterly dividends on our ordinary shares, we cannot give an assurance that dividends will be paid, or predict the amount of any dividends. Future dividends will depend on a number of factors prevailing at the time our board of directors considers any dividend payment. The following table shows the cash dividend amounts to all shareholders since 2010 on a per share basis and in aggregate.

				Ordinary dividend per share						Ordinary dividend per
Fiscal year	Curr.	Q1	Curr.	Q2	Curr.	Q3	Curr.	Q4	Curr.	share
2011									NOK	6.5000
2012									NOK	6.7500
2013									NOK	7.0000
2014	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	1.8000	NOK	7.2000
2015	NOK	1.8000							NOK	1.8000
2015			USD	0.2201	USD	0.2201	USD	0.2201	USD	0.6603

Statoil commenced quarterly dividends in 2014. During 2015 Statoil paid four quarterly dividends. The third quarter 2014 dividend was paid out in February 2015, the fourth quarter 2014 dividend was paid out in May 2015, the first quarter 2015 dividend was paid out in August 2015 and the second quarter 2015 dividend was paid out in November 2015. The third quarter 2015 dividend was paid out in February 2016. The proposed fourth quarter 2015 dividend will be considered at the annual general meeting 11 May 2016. The Statoil share will be traded ex dividend 12 May 2016 and if approved, the dividend will be disbursed around late June 2016. For US ADR holders, the ex-dividend date will be 12 May 2016 and expected payment date for ADR holders will be in June 2016.

From the second quarter 2015 Statoil implemented declaring dividends in USD. As from the third quarter 2015 only dividend in USD per share will be announced. Dividends in NOK per share will be communicated four business days after record date for shareholders at Oslo Børs. Since we will declare dividends in USD, exchange rate fluctuations will affect the amounts in NOK received by shareholders on the Oslo Børs.

Share repurchase

In addition to a cash dividend, Statoil may buy back shares as part of its total distribution of capital to its shareholders. For the period 2013-2015, the board of directors was authorised by the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. We have not undertaken any share repurchase based on this authorisation.

It is Statoil's intention to renew this authorisation at the annual general meeting. Statoil intends to use share buybacks more actively going forward, based on balance sheet strength considerations.

6.2 Shares purchased by issuer

Shares are acquired in the market for transfer to employees under the share savings scheme in accordance with the limits set by the board of directors. No shares were repurchased in the market for the purpose of subsequent annulment in 2015.

6.2.1 Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the company. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

Through regular salary deductions, employees can invest up to 5% of their base salary in Statoil shares. In addition, the company contributes 20% of the total share investment made by employees in Norway, up to a maximum of NOK 1,500 per year (approximately USD 170). This company contribution is a tax-free employee benefit under current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. Under current Norwegian tax legislation, the share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award.

The board of directors is authorised to acquire Statoil shares in the market on behalf of the company. The authorisation may be used to acquire own shares for a total nominal value of up to NOK 35 million. Shares acquired under this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the company's share savings plan as approved by the board of directors. The minimum and maximum amount that may be paid per share is NOK 50 and 500, respectively.

The authorisation is valid until the next annual general meeting, but not beyond 30 June 2016. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share savings plan granted by the annual general meeting 14 May 2014. It is Statoil's intention to renew this authorisation at the annual general meeting. Statoil intends to use share buybacks more actively going forward, based on balance sheet strength considerations.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 35 million, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than 14 million shares.

Period in which shares were repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of programme	Maximum number of shares that may yet be purchased under the programme authorisation 1)
Jan-15	713,771	130.6301	4,713,258	6,286,742
Feb-15	628,251	149.5611	5,341,509	5,658,491
Mar-15	700,062	134.5595	6,041,571	4,958,429
Apr-15	598,244	157.0929	6,639,815	4,360,185
May-15	605,625	154.6826	7,245,440	3,754,560
Jun-15	664,037	140.9826	664,037	13,335,963
Jul-15	661,604	141.2402	1,325,641	12,674,359
Aug-15	707,278	132.0766	2,032,919	11,967,081
Sep-15	781,215	119.1604	2,814,134	11,185,866
Oct-15	661,646	140.4563	3,475,780	10,524,220
Nov-15	717,182	129.8833	4,192,962	9,807,038
Dec-15	750,203	123.5585	4,943,165	9,056,835
Jan-16	878,834	102.6997	5,821,999	8,178,001
Feb-16	745,858	117.5826	6,567,857	7,432,143
TOTAL	9,813,810 2)	132.4013 3)		

1) The authorisation to repurchase a maximum of 11 million shares with a maximum overall nominal value of NOK 27.5 million for repurchase of shares in connection with the share savings plan was given by the annual general meeting on 14 May 2014. The authorisation was maintained by the annual general meeting on 19 May 2015 at a maximum of 14 million shares with a maximum overall nominal value of 35 million for repurchase of shares, valid until 30 June 2016.

2) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

3) Weighted average price per share.

6.3 Information and communications

Updated information about Statoil's financial performance and future prospects forms the basis for assessing the value of the company.

Information provided to the stock market must be transparent and ensure equal treatment of all shareholders, and it must aim to provide shareholders with correct, clear, relevant and timely information that forms the basis for assessing the value of the company.

Statoil shares are listed on the Oslo Børs, and its American Depositary Receipts (ADRs) are listed on the New York Stock Exchange. We distribute share price-sensitive information through the international wire services, the Oslo Børs in Norway, the Securities and Exchange Commission in the US, and our website Statoil.com.

Our registrar manages our shares listed on the Oslo Børs on our behalf and provides the connection to the Norwegian Central Securities Depository (VPS). Important services provided by the registrar are investor services for private shareholders, the disbursement of dividends and assistance at our general meetings. DnB Bank is currently the account registrar for Statoil.

6.3.1 Investor contact

Our investor relations staff function (IR) coordinates the dialogue with our shareholders.

We place great emphasis on ensuring that relevant and timely information is distributed to the capital markets. Given the size and diversity of our shareholder base, the opportunities for direct shareholder interaction are limited. Our "Investor Centre" web pages are therefore specially designed for investors and analysts who wish to follow the company's progress - Statoil.com/IR.

We broadcast our quarterly presentations and other relevant presentations by management directly on the internet, and the related reports are made available together with other relevant information on our website.

Ticker Codes:
Oslo Børs: STL
New York Stock Exchange: STO
Reuters: STL.OL
Bloomberg: STL NO

Financial calendar for 2016

04 February	Fourth quarter results and strategy update
16 February	Q3 2015 ADS trading ex-dividend
17 February	Q3 2015 ordinary share trading ex-dividend
26 February	Q3 2015 ordinary share dividend payment
04 March	Q3 2015 ADS dividend payment
18 March	Publication annual report 2015
27 April	First quarter 2016
11 May	Annual general meeting
12 May	Q4 2015 ADS trading ex-dividend
12 May	Q4 2015 ordinary share trading ex-dividend
June	Q4 2015 ordinary share dividend payment
June	Q4 2015 ADS dividend payment
27 July	Second quarter 2016
end August	Q1 2016 ADS trading ex-dividend
end August	Q1 2016 ordinary share trading ex-dividend
end August	Q1 2016 ordinary share dividend payment
early September	Q1 2016 ADS dividend payment
27 October	Third quarter 2016
end November	Q2 2016 ADS trading ex-dividend
end November	Q2 2016 ordinary share trading ex-dividend
end November	Q2 2016 ordinary share dividend payment
early December	Q2 2016 ADS dividend payment

6.4 Market and market prices

The principal trading market for our ordinary shares is the Oslo Børs. The ordinary shares are also listed on the New York Stock Exchange, trading in the form of American Depositary Shares (ADS).

Statoil's shares have been listed on the Oslo Børst since our initial public offering on 18 June 2001. The ADSs traded on the New York Stock Exchange are evidenced by American Depositary Receipts (ADR), and each ADS represents one ordinary share. Statoil has a sponsored ADR facility with Deutsche Bank Trust Company Americas as depositary.

6.4.1 Share prices

These are the reported high and low quotations at market closing for the ordinary shares on the Oslo Børs and New York Stock Exchange for the periods indicated.

They are derived from the Oslo Børs Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

	NOK per ordinary share		USD per ADS	
Share price	High	Low	High	Low
Year ended 31 December				
2011	160.50	113.70	29.58	20.16
2012	162.40	133.80	28.92	22.15
2013	147.70	123.00	27.00	20.14
2014	194.80	120.00	31.91	15.82
2015	160.80	116.30	21.31	13.42
Quarter ended				
Monday, March 31, 2014	171.30	146.40	28.51	23.37
Monday, June 30, 2014	194.80	164.90	31.91	27.60
Tuesday, September 30, 2014	191.00	171.90	31.01	26.93
Tuesday, December 31, 2014	173.70	120.00	26.79	15.82
Tuesday, March 31, 2015	149.80	125.80	19.62	16.25
Tuesday, June 30, 2015	160.80	140.10	21.31	17.59
Wednesday, September 30, 2015	141.40	116.30	17.56	13.85
Wednesday, December 30, 2015	145.60	118.70	17.74	13.42
March, up until 8 March 2016	133.80	97.90	15.94	11.38
Month of				
September 2015	126.80	116.80	15.31	13.85
October 2015	144.70	126.40	17.74	14.83
November 2015	145.60	129.70	17.06	14.90
December 2015	135.70	118.70	15.70	13.42
January 2016	123.50	97.90	13.96	11.38
February 2016	127.10	108.00	14.56	12.49
March up until 8 March 2016	133.80	127.30	15.94	14.78

6.4.2 Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.

As depositary from 31 January 2013, Deutsche Bank Trust Company Americas collects its fees for the delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal, or from intermediaries acting for them. The depositary collects fees from investors by deducting the fees from the amounts distributed or by selling a portion of distributable property to pay the fees. The depositary may refuse to provide fee-attracting services until its fees for those services are paid.

The charges of the depositary payable by investors are as follows:

Persons depositing or withdrawing shares must pay:	For:
USD 5.00 (or less) per 100 ADSs (or portion of 100 ADSs)	• Issuance of ADSs, including issuances resulting from a distribution of shares or rights or other property • Cancellation of ADSs for the purpose of withdrawal, including if the deposit agreement terminates
USD 0.02(or less) per ADS, subject to the company's consent	• Any cash distribution to ADS registered holders
USD 0.05 (or less) per ADS, subject to the company's consent	• For the operation and maintenance costs in administering the ADR program
A fee equivalent to the fee that would be payable if securities distributed to you had been shares and the shares had been deposited for issuance of ADSs	• Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	• Transfer and registration of shares on our share register to or from the name of the Depositary or its agent when you deposit or withdraw shares
Expenses of the Depositary	• Cable, telex and facsimile transmissions (as provided in the deposit agreement) • Converting foreign currency to US dollars
Taxes and other governmental charges the Depositary or the custodian have to pay on any ADS or share underlying an ADS, for example, stock transfer taxes, stamp duty or withholding taxes	• As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	• As necessary

Reimbursements and payments made and fee waivers granted by the depositary
The depositary has agreed to reimburse certain company expenses related to the company's ADR programme and incurred by the company in connection with the programme. In the year ended 31 December 2015, the depositary reimbursed approximately USD 1.43 million to the company in relation to certain expenses including investor relations expenses, expenses related to the maintenance of the ADR programme, legal counsel fees, printing and ADR certificates.

The depositary has also agreed to waive fees for costs associated with the administration of the ADR programme, and it has paid certain expenses directly to third parties on behalf of the company. The expenses paid to third parties include expenses relating to reporting services and access charges to its online platform, re-registration costs borne by the custodian. For the year ended 31 December 2015, the depositary paid expenses of approximately USD 69,576 directly to third parties.

6.5 Taxation

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway and to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and American Depositary Shares (ADS). The term “shareholder” refers to both holders of shares and holders of ADSs, unless otherwise explicitly stated.

Norwegian tax matters
The outline does not provide a complete description of all tax regulations that might be relevant (i.e. for investors to whom special regulations may be applicable), and is based on current law and practice. Shareholders should consult their professional tax adviser for advice about individual tax consequences.

Taxation of dividends
Corporate shareholders (i.e. limited liability companies and similar entities) residing in Norway for tax purposes are generally subject to tax in Norway on dividends received from Norwegian companies. The basis for taxation is 3% of the dividends received, which is subject to the standard income tax rate. The standard income tax rate has been reduced from 27% in 2015 to 25% in 2016.

Individual shareholders resident in Norway for tax purposes are subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016) in Norway for dividend income exceeding a basic tax free allowance. However, in 2016 dividend income exceeding the basic tax free allowance is grossed up with a factor of 1.15 before taken to taxation, resulting in an effective tax rate of 28.75% (25% x 1.15). The tax free allowance is computed for each individual share or ADS on the basis of the cost price of that share or ADS multiplied by a risk-free interest rate. The risk-free interest rate will be determined every income year. Any part of the calculated allowance for one year that exceeds the dividend distributed for the share or ADS ("unused allowance") may be carried forward and set off against future dividends received for (or gains upon the realisation of, see below) the same share or ADS. Any unused allowance will also be added to the basis for computation of the allowance for the same share or ADS the following year.

Non-resident shareholders are as a rule subject to withholding tax at a rate of 25% on dividends distributed by Norwegian companies. This withholding tax does not apply to corporate shareholders in the EEA area that document that they are genuinely established and carry on genuine economic business activity within the EEA area, provided that Norway is entitled to receive information from the state of residence pursuant to a tax treaty or other international treaty. If no such treaty exists with the state of residence, the shareholder may instead present confirmation issued by the tax authorities of the state of residence verifying the documentation. Individual shareholders resident for tax purposes in the EEA area may apply to the Norwegian tax authorities for a refund if the tax withheld by the distributing company exceeds the tax that would have been levied on individual shareholders resident in Norway.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. Generally, the treaty rate does not exceed 15% and, in cases where a corporate shareholder holds a qualifying percentage of ownership in the distributing company, the withholding tax rate on dividends may be further reduced. The withholding tax rate in the tax treaty between the United States and Norway is currently 15% in all cases. It is the responsibility of the distributing company to deduct the withholding tax when dividends are paid to non-resident shareholders.

The reduced withholding rate will generally only apply to dividends paid on shares held by shareholders who are able to properly demonstrate to the company that they are entitled to the benefits of the tax treaty.

For holders of shares and ADSs deposited with Deutsche Bank Trust Company Americas (Deutsche Bank), documentation establishing that the holder is eligible for the benefits under the tax treaty with Norway, may be provided to Deutsche Bank. Deutsche Bank has been granted permission by the Norwegian tax authorities to receive dividends from us for redistribution to a beneficial owner of shares and ADSs at the applicable treaty withholding rate.

Dividends paid to shareholders (either directly or through a depositary) who have not provided the relevant documentation to the relevant party that they are eligible for the reduced rate, will be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office - Foreign Tax Affairs (COFTA) for a refund of the excess amount of tax withheld.

According to information provided by the Central Office of Foreign Tax Affairs (COFTA), an application for a refund of withholding tax from shareholders must contain the following:

1. Full name, address and tax identification number of the claimant.
2. Payment details, including name of account holder, either a Norwegian bank account number or IBAN and SWIFT/BIC code. The IBAN account must be able to receive NOK as the refund will be transferred in NOK.
3. A specification of the Norwegian company(ies) involved, the exact amount of shares, the date of each dividend payment, the dividend per share, the total dividend payment, the Norwegian withholding tax rate, and the reclaimed amount. All amounts must be given in NOK.
4. Documentation that confirms the claimant's residency.
    - A claim according to a tax treaty must contain a Certificate of Residence issued by the competent local tax authorities with reference to the claimant's tax identification number. The certificate of residence must state that the claimant was resident according to the tax treaty with Norway during the year when the decision to distribute the dividend was made. The confirmation must be in original. The Certificate of Residence must mention solely the claimant's name

- A claim according to the tax exemption method cf. tax act section 2-38 must contain confirmation that the claimant is registered and based within the EEA and genuinely established in that country

5. A credit advice, certifying that the claimant has received the dividends and has been subject to Norwegian withholding tax on the dividends. The credit advice must fill the following criteria:
   - It must document the chain of transactions, including information about the foreign custodian/bank/clearing central registered in Norway that initially received the dividends. If the dividends have been paid through a chain of transactions, each transaction must be documented with a credit advice issued to the initial receiver
   - It must be issued by the bank that credits the claimant the dividend payment. It must contain the following details:
     - Name of the payment recipient, i.e. the claimant
     - Name and ISIN of the stock etc
     - The exact amount of shares
     - The gross amount and withholding tax in NOK
     - The ex-date, the record date and the pay-date
     - The dividend per share

   Please note that the credit advice must specify that the dividend payment has been subject to withholding tax, not just tax. This clarification will be a definite requirement on claims made from 1 January 2014 onward.
6. Power of attorney/attestation, a general power of attorney from the beneficial owner to authorise the claimant to claim a refund.
   The power of attorney does not need to mention the specific dividend payments. Still, COFTA requires that the claimant makes a spreadsheet listing the names of the companies from which the dividends were received, with the dates and the amounts of withholding tax. This spreadsheet should accompany the application and has to be approved and signed by the beneficial owner.
   Please note that only one refund claim can be made regarding each dividend payment, and applications for the same claim must not be filed several times, neither directly nor via custodians.
7. A claim should also contain general information about the claimant as regards legal, corporate and taxable aspects. Please note that only the beneficial owner may apply for a refund of withholding tax. An entity that is acting on behalf of someone else as either trustee or investment manager, and who is as such the registered or indirect owner of the dividends, is not entitled to a refund. Neither is an entity that receives the dividend payments and passes them directly on to other entities/persons entitled to a refund.

In some cases COFTA may request further, and more specific, information about the claim for refund and the claimant. An assessment of the entity and of the validity of the claim is made in each individual case.

The application should be sent to the following address: Central Office Foreign Tax Affairs/Sentralskattekontoret for utenlandssaker, Postboks 8031, 4068 Stavanger, NORWAY

Corporate shareholders that carry on business activities in Norway, and whose shares or ADSs are effectively connected with such activities are not subject to withholding tax. For such shareholders, 3% of the received dividends are subject to the standard income tax rate (reduced from 27% in 2015 to 25% in 2016).

Taxation on the realisation of shares and ADSs

Corporate shareholders resident in Norway for tax purposes are not subject to tax in Norway on gains derived from the sale, redemption or other disposal of shares or ADSs in Norwegian companies. Capital losses are not deductible.

Individual shareholders residing in Norway for tax purposes are subject to tax in Norway on the sale, redemption or other disposal of shares or ADSs. Gains or losses in connection with such realisation are included in the individual's ordinary taxable income in the year of disposal, which is subject to the standard income tax rate, being reduced from 27% in 2015 to 25% in 2016. However, in 2016 the taxable gain or deductible loss is grossed up with a factor of 1.15 before included in the ordinary taxable income, resulting in an effective tax rate of 28.75% (25% x 1.15).

The taxable gain or deductible loss (before gross up) is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares or ADSs. Any unused allowance pertaining to a share may be deducted from a taxable gain on the same share or ADS, but may not lead to or increase a deductible loss. Furthermore, any unused allowance may not be set off against gains from the realisation of the other shares or ADSs.

If the shareholder disposes of shares or ADSs acquired at different times, the shares or ADSs that were first acquired will be deemed to be first sold (the "FIFO" principle) when calculating the taxable gain or loss.

A corporate shareholder or an individual shareholder who ceases to be tax resident in Norway due to domestic law or tax treaty provisions may, in certain circumstances, become subject to Norwegian exit taxation on capital gains related to shares or ADSs.

Shareholders not residing in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder carries on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities.

Wealth tax

The shares or ADSs are included in the basis for the computation of wealth tax imposed on individuals resident in Norway for tax purposes. Norwegian limited companies and certain similar entities are not subject to wealth tax. The current marginal wealth tax rate is 0.85% of the value assessed. The assessment value of listed shares (including ADSs) is 100% of the listed value of such shares or ADSs on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares and ADSs in Norwegian limited companies unless the shareholder is an individual and the shareholding is effectively connected with the individual's business activities in Norway.

Inheritance tax and gift tax
No inheritance or gift tax is imposed in Norway.

Transfer tax
No transfer tax is imposed in Norway in connection with the sale or purchase of shares or ADSs.

United States tax matters
This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you if you hold your shares or ADSs as capital assets for tax purposes. This section does not apply to you if you are a member of a special class of holders subject to special rules, including:

- dealers in securities
- traders in securities that elect to use a mark-to-market method of accounting for their securities holdings
- tax-exempt organisations
- life insurance companies
- persons liable for alternative minimum tax
- persons that actually or constructively own 10% or more of the voting stock of Statoil
- persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction
- persons that purchase or sell shares or ADSs as part of a wash sale for tax purposes or
- persons whose functional currency is not USD

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs and ADRs for shares will not generally be subject to United States federal income tax.

If a partnership holds the shares or ADSs, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the shares or ADSs should consult its tax adviser with regard to the United States federal income tax treatment of an investment in the shares or ADSs.

You are a "US holder" if you are a beneficial owner of shares or ADSs and you are for United States federal income tax purposes:

- a citizen or resident of the United States;
- a United States domestic corporation;
- an estate whose income is subject to United States federal income tax regardless of its source; or
- a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorised to control all substantial decisions of the trust.

You should consult your own tax adviser regarding the United States federal, state and local and Norwegian and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends
If you are a US holder, the gross amount of any dividend paid by Statoil out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes) is subject to United States federal income taxation. If you are a non-corporate US holder, dividends paid to you will be eligible to be taxed at the preferential rates applicable to long-term capital gains as long as, in the year that you receive the dividend, the shares or ADSs are readily tradable on an established securities market in the United States or Statoil is eligible for benefits under the Treaty. To qualify for the preferential rates, you must hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet certain other requirements. Furthermore, these tax consequences would be different if Statoil were to be treated as a PFIC as discussed below.

You must include any Norwegian tax withheld from the dividend payment in this gross amount even though you do not in fact receive the amount withheld as tax. The dividend is taxable for you when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the value in USD of the payments made in NOK determined at the spot NOK/USD rate on the date the dividend distribution is includible in your income, regardless of whether or not the payment is in fact converted into USD. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to the extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid to Norway will be creditable or deductible against your United States federal income tax liability. Special rules apply when determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. To the extent that a refund of the tax withheld is available to you under Norwegian law, the amount of tax withheld that is refundable will not be eligible for credit against your United States federal income tax liability. Dividends will be income from sources outside the United States and will generally, depending on your circumstances, be either "passive" or "general" income for purposes of computing the foreign tax credit allowable to you.

Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into USD will generally be treated as ordinary income or loss and will not be eligible for the special tax rate. Such gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

Taxation of capital gains
Subject to the PFIC rules discussed below, if you are a US holder and you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in USD of the amount that you realise and your tax basis, determined in USD, in your shares or ADSs. A capital gain of a non-corporate US holder is generally taxed at preferential rates if the property is held for more than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

If you receive any foreign currency on the sale of shares or ADSs, you may recognise ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into USD. You should consult your own tax adviser regarding how to account for payments made or received in a currency other than USD.

PFIC rules
We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, if you are a US holder, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs. Amounts allocated to the year in which the gain is realised or the "excess distribution" is received or to a taxable year before we were classified as a PFIC would be subject to tax at ordinary income tax rates, and amounts allocated to all other years would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, the shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the preferential tax rates if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

Tax Filings
You should consult your own advisers regarding any tax filing or reporting obligations that arise out of the acquisition, ownership or disposition of shares or ADSs. Failure to comply with certain US tax filing or reporting obligations can cause you to be subject to significant penalties.

6.6 Exchange controls and limitations

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval.

An exception applies to the physical transfer of payments in currency exceeding certain thresholds, which must be declared to the Norwegian custom authorities.

This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank or other licensed payment institution.

There are no restrictions affecting the rights of non-Norwegian residents or foreign owners to hold or vote for our shares.

6.7 Exchange rates

The table below shows the high, low, average and end-of-period exchange rates for the Norwegian krone for USD 1.00 as announced by Norges Bank (Norway's central bank).

The average is computed using the monthly average exchange rates announced by Norges Bank during the period indicated.

For the year ended 31 December	Low	High	Average	End of Period
2011	5.2369	6.0315	5.6059	5.9927
2012	5.5349	6.1471	5.8172	5.5664
2013	5.4438	6.2154	5.8753	6.0837
2014	5.8611	7.6111	6.3011	7.4332
2015	7.3593	8.8090	8.0637	8.8090

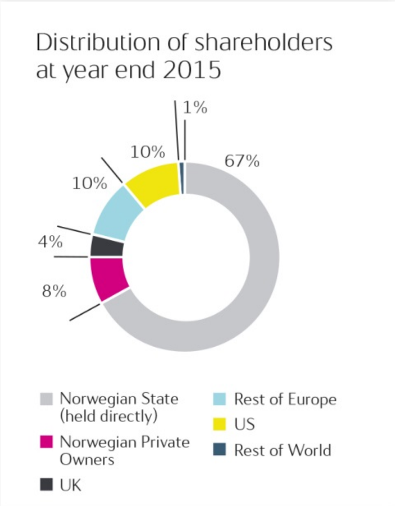
	Low	High
2015		
September	8.0891	8.5783
October	8.0524	8.5700
November	8.4636	8.6929
December	8.4842	8.8090
2016		
January	8.6641	8.9578
February	8.5111	8.7294
March (up to and including 8 March 2016)	8.5441	8.6791

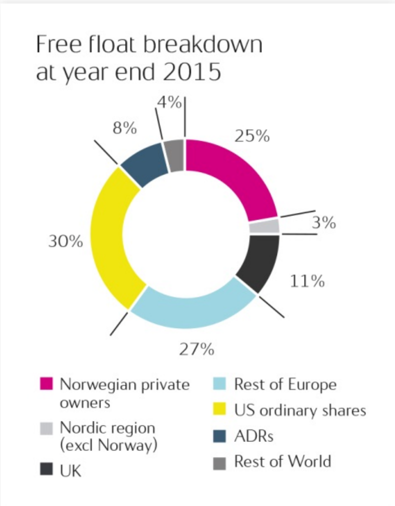
On 8 March 2016, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 8.5496.

Fluctuations in the exchange rate between the Norwegian krone and the US dollar will affect the amounts in US dollars received by holders of American Depositary Shares (ADSs) on the conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares, and they may affect the US dollar price of the ADSs on the New York Stock Exchange.

6.8 Major shareholders

The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.





Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the Norwegian parliament's decision of 2001 concerning a minimum state shareholding in Statoil of two-thirds, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67%, and the Government's direct purchase of Statoil shares was completed.

As of 31 December 2015, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.23% indirect interest through the National Insurance Fund (Folketrygdfondet), totaling 70.23%.

The Norwegian State is the only person or entity known to us to own beneficially, directly or indirectly, more than 5% of our outstanding shares. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as of 31 December 2015.

Statoil has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any voting rights that differ from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of at least two-thirds of the votes cast as well as of the votes represented at a general meeting is required to amend our articles of association. As long as the Norwegian State owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association. Since the Norwegian State, acting through the Norwegian Minister of Petroleum and Energy, has in excess of two-thirds of the shares in the company, it has sole power to amend our articles of association. In addition, as majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our board of directors and approve the dividend proposed by the board of directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

Shareholders at December 2015		Number of Shares	Ownership in %
1	Government of Norway	2,136,393,559	67.00%
2	Folketrygdfondet	103,124,812	3.20%
3	SAFE Investment Company Limited	32,256,434	1.00%
4	BlackRock Institutional Trust Company, N.A.	31,513,618	1.00%
5	INVESCO Asset Management Limited	26,461,451	0.80%
6	Schroder Investment Management Ltd. (SIM)	23,330,607	0.70%
7	The Vanguard Group, Inc.	19,539,470	0.60%
8	Allianz Global Investors GmbH	18,371,484	0.60%
9	KLP Forsikring	16,642,798	0.50%
10	Storebrand Kapitalforvaltning AS	14,448,698	0.50%
11	BlackRock Investment Management, LLC	13,995,472	0.40%
12	Epoch Investment Partners, Inc.	13,815,430	0.40%
13	State Street Global Advisors (US)	13,670,590	0.40%
14	DNB Asset Management AS	13,641,273	0.40%
15	Fidelity Worldwide Investment (UK) Ltd.	11,886,480	0.40%
16	Acadian Asset Management LLC	11,578,950	0.40%
17	TIAA-CREF	11,231,159	0.40%
18	T. Rowe Price Associates, Inc.	11,003,874	0.30%
19	APG Asset Management	10,436,861	0.30%
20	AXA Investment Managers UK Ltd.	10,075,894	0.30%

Source: Data collected by third party, authorized by Statoil, December 2015

7 Corporate governance

Statoil's objective is to create long-term value for its shareholders through the exploration for and production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

In pursuing its corporate objective, Statoil is committed to the highest standard of governance and to cultivating a values-based performance culture that rewards exemplary ethical practices, respect for the environment and personal and corporate integrity. Statoil believes that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly defined division of roles and responsibilities between the shareholders, the board of directors and the company's management.

Statoil's governing structures and controls help to ensure that Statoil runs its business in a profitable manner for the benefit of shareholders, employees and other stakeholders in the societies in which Statoil operates.

The following principles underline Statoil's approach to corporate governance:
- All shareholders will be treated equally
- Statoil will ensure that all shareholders have access to up-to-date, reliable and relevant information about its activities
- Statoil will have a board of directors that is independent (as defined by Norwegian Standards) of the group's management. The board focuses on preventing conflicts of interest between shareholders, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in Statoil is subject to regular review and discussion by the board of directors.

Statoil's board of directors endorses the "Norwegian Code of Practice for Corporate Governance". The company's compliance with, and deviations from, the code's recommendations are commented on in a separate corporate governance statement issued by Statoil's board of directors. This statement, which contains further details on the corporate governance of Statoil, is available at www.statoil.com/cg.

7.1 Articles of association

The articles of association and the Norwegian Public Limited Liability Companies Act form the legal framework for Statoil's operations.

Statoil's current articles of association were adopted at the annual general meeting of shareholders on 14 May 2013.

Summary of Statoil's articles of association:

Name of the company
The registered name is Statoil ASA. Statoil is a Norwegian public limited company.

Registered office
Statoil's registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 923 609 016.

Object of the company
The object of Statoil is, either by itself or through participation in or together with other companies, to engage in the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other business.

Share capital
Statoil's share capital is NOK 7,971,617,757.50 divided into 3,188,647,103 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Statoil's articles of association provide that the board of directors shall consist of nine to 11 directors. The board, including the chair and the deputy chair, shall be elected by the corporate assembly for a period of up to two years.

Corporate assembly
Statoil has a corporate assembly comprising 18 members who are normally elected for a term of two years. The general meeting elects 12 members with four deputy members, and six members with deputy members are elected by and from among the employees.

General meetings of shareholders
Statoil's annual general meeting is held no later than 30 June each year.

The meeting will consider the annual report and accounts, including the distribution of any dividend, and any other matters required by law or the articles of association.

Documents relating to matters to be dealt with at general meetings do not need to be sent to all shareholders if the documents are accessible on Statoil's website. A shareholder may nevertheless request that such documents be sent to him/her.

Shareholders may vote in writing, including through electronic communication, for a period before the general meeting. In order to practise advance voting, the board of directors must stipulate applicable guidelines. Statoil's board of directors adopted guidelines for such advance voting in March 2012, and these guidelines are described in the notices of the annual general meetings.

Marketing of petroleum on behalf of the Norwegian State
Statoil's articles of association provide that Statoil is responsible for marketing and selling petroleum produced under the SDFI's shares in production licences on the Norwegian continental shelf (NCS) as well as petroleum received by the Norwegian State paid as royalty together with its own production. Statoil's general meeting adopted an instruction in respect of such marketing on 25 May 2001, as most recently amended by authorisation of the annual general meeting on 19 May 2011.

Nomination committee
The tasks of the nomination committee are to make recommendations to the general meeting regarding the election of and fees for shareholder-elected members and deputy members of the corporate assembly, to make recommendations to the corporate assembly regarding the election of and fees for shareholder-elected members of the board of directors, to make recommendations to the corporate assembly regarding the election of the chair and the deputy chair of the board and to make recommendations to the general meeting regarding the election of and fees for members of the nomination committee.

The general meeting may adopt instructions for the nomination committee.

The full articles of association are available at Statoil.com/articlesofassociation.

7.2 Code of Conduct

Ethics - Statoil's approach
Statoil believes that responsible and ethical behavior is a necessary condition for a sustainable business. Statoil's Code of Conduct (the Code) is based on its values and reflects Statoil's commitment to high ethical standards in all its activities.

Our Code of Conduct
The Code describes Statoil's code of business practice and the requirements to expected behavior in areas such as anti-corruption, fair competition, human rights and non-discrimination working environments with equal opportunity. The Code applies to Statoil's board members, employees and hired personnel.

Statoil seeks to work with others who share its commitment to ethics and compliance, and Statoil manages its risks through in-depth knowledge of suppliers, business partners and markets. Statoil expects its suppliers and business partners to comply with applicable laws, respect internationally recognised human rights and adhere to ethical standards which are consistent with Statoil's ethical requirements when working for or together with Statoil. In joint ventures and entities where Statoil does not have control, Statoil makes good faith efforts to encourage the adoption of ethics and anti-corruption policies and procedures that are consistent with itss standards. Anyone working for Statoil who does not comply with the Code faces disciplinary action, up to and including summery dismissal or termination of their contract.

Training and Certifying the Code
Code of Conduct training and comprehensive trainings on specific issues, including anti-corruption and anti-trust, is carried out to explain how the Code applies and to describe the tools that Statoil has made available to address risk.

All Statoil employees have to annually confirm electronically that they understand and will comply with the Code (Code certification). The Code certification reminds the individuals of their duty to comply with Statoil's values and ethical requirements and creates an environment with open dialog on ethical issues, both internally and externally.

Anti-corruption compliance programme
Statoil is against all forms of corruption including bribery, facilitation payments and trading in influence and has a company-wide anti-corruption compliance programme which implements its zero-tolerance policy. The programme includes mandatory procedures designed to comply with applicable laws and regulations and training on relevant issues such as gifts, hospitality and conflicts of interest. Compliance officers, who are responsible for ensuring that ethics and anti-corruption considerations are integrated into Statoil's business activities, constitute an important part of the programme.

In 2015, Statoil focused on the systematic support and follow up of its compliance officers in the business units and on strengthening the compliance officer network within Statoil. Further, the Statoil Code of Conduct was subject to a comprehensive review, and was updated and made more user-friendly. In 2016 , the new Code will be rolled out and implemented.

Speak Up
Statoil is committed to maintain an open dialog on ethical issues. The Code requires those who have a question or suspect misconduct to raise their concern either through internal channels or through Statoil's external Ethics Helpline. Employees are encouraged to discuss their concerns with their supervisor. Statoil recognises that raising a concern is not always easy so there are have several internal channels for taking concerns forward, including through human resources or the ethics and compliance function in the legal department. Concerns can also be expressed through the externally operated Ethics Helpline which is available 24/7, and allows for anonymous reporting and two-way communication through the use of a pin-code. Statoil has a non-retaliation policy for anyone who reports in good faith.

More information about Statoil's policies and requirements related to the Code of Conduct is available on Statoil.com/ethics.

7.3 General meeting of shareholders

The general meeting of shareholders is Statoil's supreme corporate body. The objective of the general meeting is to ensure shareholder democracy and all shareholders are encouraged to participate in person or by proxy.

The general meeting of shareholders is Statoil's supreme corporate body. The 2016 annual general meeting (AGM) is scheduled for 11 May 2016 in Stavanger, Norway, with simultaneous transmission by webcast through our website. The AGM is conducted in Norwegian, with simultaneous English translation during the webcast.

The main framework for convening and holding Statoil's AGM is as follows:

Pursuant to Statoil's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documents relating to the AGM are published on Statoil's website and notice is sent to all shareholders with known addresses at least 21 days prior to the meeting. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. Other documents relating to Statoil's AGMs will be made available on Statoil's website. A shareholder may nevertheless request that documents that relate to matters to be dealt with at the AGM be sent to him/her.

Shareholders are entitled to have their proposals dealt with at the AGM if the proposal has been submitted in writing to the board of directors in sufficient time to enable it to be included in the notice of meeting, i.e. no later than 28 days before the meeting. Shareholders who are unable to attend may vote by proxy.

As described in the notice of the general meeting, shareholders may vote in writing, including through electronic communication, for a period before the general meeting.

The deadline for registration for the AGM in Statoil is the day before the AGM is due to take place.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties, or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM. This is in order to ensure impartiality in relation to the matters to be considered. As Statoil has a large number of shareholders with a wide geographical distribution, Statoil offers shareholders the opportunity to follow the AGM by webcast.

The following matters are decided at the AGM:
- Approval of the board of directors' report, the financial statements and any dividend proposed by the board of directors and recommended by the corporate assembly
- Election of the shareholders' representatives to the corporate assembly and approval of the corporate assembly's fees
- Election of the nomination committee and approval of the nomination committee's fees
- Election of the external auditor and approval of the auditor's fee
- Any other matters listed in the notice convening the AGM

All shares carry an equal right to vote at general meetings. Resolutions at general meetings are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. Such matters require the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting.

If shares are registered by a nominee in the Norwegian Central Securities Depositary (VPS), cf. section 4-10 of the Norwegian Public Limited Liability Companies Act, and the beneficial shareholder wants to vote for their shares, the beneficial shareholder must re-register the shares in a separate VPS account in their own name prior to the general meeting. If the holder can prove that such steps have been taken and that the holder has a de facto shareholder interest in the company, the holder may, in the company's opinion, vote for the shares. Decisions regarding voting rights for shareholders and proxy holders are made by the person opening the meeting, whose decisions may be reversed by the general meeting by simple majority vote.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards to extraordinary general meetings (EGM), an EGM will be held in order to consider and decide a specific matter if demanded by the corporate assembly, the chair of the corporate assembly, the auditor or shareholders representing at least 5% of the share capital. The board must ensure that an EGM is held within a month of such demand being submitted.

In the following, certain types of resolutions by the general meeting of shareholders are outlined:

New share issues
If Statoil issues any new shares, including bonus shares, the articles of association must be amended. This requires the same majority as other amendments to the articles of association. In addition, under Norwegian law, the shareholders have a preferential right to subscribe for new shares issued by Statoil. The preferential right to subscribe for an issue may be waived by a resolution of a general meeting passed by the same percentage majority as required to approve amendments to the articles of association. The general meeting may, with a majority as described above, authorise the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such share issues. Such authorisation may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorisation was granted.

The issuing of shares through the exercise of preferential rights to holders who are citizens or residents of the USA may require Statoil to file a registration statement in the USA under US securities laws. If Statoil decides not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares
Statoil's articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided upon by a general meeting of shareholders by a two-thirds majority on certain conditions. However, such share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if authorisation to do so has been granted by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the general meeting. The aggregate par value of such treasury shares held by the company must not exceed 10% of the company's share capital, and treasury shares may only be acquired if, according to the most recently adopted balance sheet, the company's distributable equity exceeds the consideration to be paid for the shares. Pursuant to Norwegian law, authorisation by the general meeting cannot be granted for a period exceeding 18 months.

Distribution of assets on liquidation
Under Norwegian law, a company may be wound up by a resolution of the company's shareholders at a general meeting passed by both a two-thirds majority of the aggregate votes cast and a two-thirds majority of the aggregate share capital represented at the general meeting. The shares are ranked equally in the event of a return on capital by the company upon winding up or otherwise.

7.4 Nomination committee

Pursuant to Statoil's articles of association, the nomination committee shall consist of four members who are shareholders or representatives of shareholders.

The committee is independent of both the board of directors and the company's management.

The duties of the nomination committee are to submit recommendations to:
- the annual general meeting for the election of shareholder-elected members and deputy members of the corporate assembly, and the remuneration of members of the corporate assembly
- the annual general meeting for the election and remuneration of members of the nomination committee
- the corporate assembly for the election of shareholder-elected members of the board of directors and remuneration of the members of the board of directors and
- the corporate assembly for the election of the chair and deputy chair of the corporate assembly

Using a form on Statoil's website, shareholders can propose candidates for the board of directors, the corporate assembly and the nomination committee.

The members of the nomination committee are elected by the annual general meeting. The chair of the nomination committee and one other member are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

Personal deputy members for one or more of the nomination committee's members may be elected in accordance with the same criteria as described above. A deputy member only meets for the member if the appointment of that member terminates before the term of office has expired.

The members of the nomination committee are:

- Olaug Svarva (chair), Managing director at Folketrygdfondet
- Tom Rathke, Group executive vice president Wealth Management at DnB
- Elisabeth Berge, Secretary general, Norwegian Ministry of Petroleum and Energy (personal deputy for Elisabeth Berge is Bjørn Ståle Haavik, Director at the Norwegian Ministry of Petroleum and Energy)
- Tone Lunde Bakker, Global head of cash management at Danske Bank

The nomination committee held 19 ordinary meetings and three telephone meetings in 2015.

The instructions for the nomination committee, including the rules of procedure, are available at Statoil.com/nominationcommittee.

7.5 Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

Name	Occupation	Place of residence	Year of birth	Position	Family relations to corporate executive committee, board or corporate assembly members	Share ownership for members as of 31.12.2015	Share ownership for members as of 08.03.2016	First time elected	Expiration date of current term
Olaug Svarva	Managing director, Folketrygdfondet	Oslo	1957	Chair, Shareholder-elected	No	0	0	2007	2016
Idar Kreutzer	CEO, Finance Norway (FNO)	Oslo	1962	Deputy chair, Shareholder-elected	No	0	0	2007	2016
Karin Aslaksen	Head of HR department, the National Police Directorate of Norway	Hosle	1959	Shareholder-elected	No	0	0	2008	2016
Greger Mannsverk	Managing director, Kimek AS	Kirkenes	1961	Shareholder-elected	No	0	0	2002	2016
Steinar Olsen	CEO, Jemso A/S	Stavanger	1949	Shareholder-elected	No	0	0	2007	2016
Tone Cathrine Lunde Bakker	Global head of cash management at Danske Bank	Oslo	1962	Shareholder-elected	No	0	0	2014	2016
Ingvald Strømmen	Dean at Norwegian University of Science and Technology (NTNU)	Ranheim	1950	Shareholder-elected	No	0	0	2006	2016
Rune Bjerke	President and CEO, DNB ASA	Oslo	1960	Shareholder-elected	No	0	0	2007	2016
Barbro Hætta	Medical doctor, University Hospital of North Norway	Harstad	1972	Shareholder-elected	No	0	0	2010	2016
Siri Kalvig	Associate professor, University of Stavanger	Stavanger	1970	Shareholder-elected	No	0	0	2010	2016
Terje Venold	Independent advisor with various directorships	Bærum	1950	Shareholder-elected	No	500	500	2014	2016
Kjersti Kleven	Co-owner of John Kleven AS	Ulsteinvik	1967	Shareholder-elected	No	0	0	2014	2016
Brit Gunn Ersland	Union representative, Tekna. Specialist Reservoir Tech.	Bergen	1960	Employee-elected	No	1,567	1,802	2011	2017
Steinar Kåre Dale	Union representative, NITO, SR Analyst	Mongstad	1961	Employee-elected	No	2,424	2,710	2013	2017
Per Martin Labråten	Union representative, Industri Energi. Production technician	Brevik	1961	Employee-elected	No	599	803	2007	2017
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee-elected	No	4,575	4,902	2006	2017
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee-elected	No	862	1,088	2008	2017
Hilde Møllerstad	Union representative, Tekna/NITO	Oslo	1966	Employee-elected	No	2,595	3,034	2013	2017
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee-elected, observer	No	816	1,023	1994	2017
Dag-Rune Dale	Union representative, Industri Energi, Safety officer	Kollsnes	1963	Employee-elected, observer	No	2,787	3,058	2013	2017
Sun Lehmann	Union representative, Tekna	Trondheim	1972	Employee-elected, observer	No	2,867	3,237	2015	2017
Total						19,592	22,157		

An election of the employee-elected members of the corporate assembly was held early 2015. Effective as of 28 April 2015, Brit Gunn Ersland was elected as new member (from the former position as an observer), Sun Lehmann was elected as a new observer and Oddvar Karlsen, Jorunn Birkeland and Sten Atle Jølle were elected as new deputy members of the corporate assembly. Eldfrid Irene Hognestad (member) left the corporate assembly as of the same date. The number of deputy members for the employee-elected members of the corporate assembly was also reduced from 17 to 11 deputy members.

Pursuant to Statoil's articles of association, the corporate assembly normally consists of 18 members. Twelve members with four deputy members are nominated by the nomination committee and elected at the general meeting of shareholders, and six members, three observers and deputy members are elected by and from among the employees. Such employees are non-executive personnel.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and the general manager cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act. The corporate assembly elects the board of directors and the chair of the board. Its responsibilities also include overseeing the board and the CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

Statoil's corporate assembly held four ordinary meetings in 2015.

All members of the corporate assembly live in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of office.

7.6 Board of directors

Pursuant to Statoil's articles of association, the board of directors consists of between nine and 11 members. The management is not represented on the board.

At present, Statoil's board of directors consists of 10 members. As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board member service contracts that provide for benefits upon termination of office. Statoil's board of directors has determined that, in its judgment, all of the shareholder representatives on the board, except for Wenche Agerup, are considered independent.

The board of directors of Statoil ASA is responsible for the overall management of the Statoil group, and for supervising the group's activities in general. The board of directors handles matters of major importance or of an extraordinary nature. However, it may require the management to refer any matter to it. The board of directors appoints the president and chief executive officer (CEO), and stipulates the job instructions, powers of attorney and terms and conditions of employment for the president and CEO.

The board of directors has three sub-committees - the "audit committee", "the safety, sustainability and ethics committee", and "the compensation and executive development committee".

The board held eight ordinary board meetings and four extraordinary meetings in 2015. Average attendance at these board meetings was 95.9%.

Members of the board of directors as of 31 December 2015:


Øystein Løseth

Øystein Løseth
Position: Shareholder-elected chair of the board and chair of the board's compensation and executive committee.
Born: 1958
Term of office: Member of the board of directors of Statoil ASA since 1 October 2014, and since 1 July 2015, also chair of the board and chair of the board's compensation and executive development committee. Up for election in 2016.
Independent: Yes
Other directorships: Chair of the board of Eidsiva Energi AS.
Number of shares in Statoil ASA as of 31 December 2015: 1,000
Loans from Statoil: None
Experience: In the period 2010 - 2014, Løseth was the CEO and before that First Senior Executive Vice President (since 2009), of Vattenfall AB. In the period 2003 – 2009, Løseth worked for NUON, a Dutch energy company, first as Division Managing Director, then as a Managing Director and the CEO, from 2006 and 2008 respectively. From 2002 to 2003, Løseth was the Head of Production, Business Development and R&D of Statkraft. In addition, he has other extensive management experience from Statkraft and Statoil, within strategy and business development among others.
Education: Løseth graduated as M.Sc. from the Norwegian University of Science and Technology and has a degree in Economics from BI Norwegian School of Management in Bergen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Løseth participated in eight ordinary board meetings, four extraordinary board meetings, three meetings of the compensation and executive development committee, four meetings of the audit committee and one meeting in the safety, sustainability and ethics committee. Løseth is a Norwegian citizen and resident in Norway.


Roy Franklin

Roy Franklin
Born: 1953
Position: Shareholder-elected deputy chair of the board, chair of the board's safety, sustainability and ethics committee and member of the board's audit committee.
Term of office: Deputy chair of the board of Statoil ASA from 1 July 2015. Franklin was also previously a member of the board of StatoilHydro from October 2007 and Statoil from November 2009 until June 2013. Up for election in 2016.
Independent: Yes
Other directorships: Non-executive chair of the board of Keller Group plc, a London-based international engineering company and Cuadrilla Resources Holdings Limited, a privately held UK company focusing on unconventional energy sources. Board member of the Australian oil and gas company Santos Ltd, the private equity firm Kerogen Capital Ltd and the London-based international engineering company Amec Foster Wheeler.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil ASA: None
Experience: Franklin has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Franklin has a Bachelor of Science in Geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Franklin participated in four ordinary board meetings, three meetings of the audit committee and two meetings of the safety, sustainability and ethics committee. Franklin is a UK citizen and resident in UK.

Bjørn Tore Godal

Bjørn Tore Godal
Born: 1945
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1 September 2010. Up for election in 2016.
Independent: Yes
Other directorships: Chair of the Council of the Norwegian Defence University College (NDUC), and vice chair of the board of the Fridtjof Nansen Institute (FNI).
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. At various times, he served as minister for trade and shipping, minister for defense, and minister of foreign affairs for a total of eight years between 1991 and 2001. From 2007-2010, Godal was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs. From 2003-2007, Godal was Norway's ambassador to Germany and from 2002-2003 he was senior adviser at the department of political science at the University of Oslo.
Education: Godal has a bachelor of arts degree in political science, history and sociology from the University of Oslo.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Godal participated in eight ordinary board meetings, three extraordinary board meetings, seven meetings of the compensation and executive development committee and five meetings of the safety, sustainability and ethics committee. Godal is a Norwegian citizen and resident in Norway.

Jakob Stausholm

Jakob Stausholm
Born: 1968
Position: Shareholder-elected member of the board and chair of the board's audit committee.
Term of office: Member of the board of Statoil ASA since July 2009. Up for election in 2016.
Independent: Yes
Other directorships: No
Number of shares in Statoil ASA as of 31 December 2015: 50,000
Loans from Statoil: None
Experience: Chief strategy and transformation officer of Maersk Line, the largest container shipping company in the world and part of A.P. Moller - Maersk Group. From 2008 to 2011, Stausholm was chief financial officer of the global facility services provider ISS A/S. Before joining ISS's corporate executive committee, he was employed by the Shell Group for 19 years and held a number of management positions, including vice president finance for the group's exploration and production in Asia and the Pacific, chief internal auditor and CFO of group subsidiaries.
Education: M.Sc. in economics from the University of Copenhagen.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Stausholm participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the audit committee. Stausholm is a Danish citizen and resident in Denmark.

Maria Johanna Oudeman

Maria Johanna Oudeman
Born: 1958
Position: Shareholder-elected member of the board and member of the board's compensation and executive development committee.
Term of office: Member of the board of Statoil ASA since 15 September 2012. Up for election in 2016.
Independent: Yes
Other directorships: Oudeman is a member of the boards of Solvay SA, Het Concertgebouw, Rijksmuseum and SHV Holdings.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil: None
Experience: Oudeman is the President of Utrecht University in the Netherlands, one of Europe's leading universities. From 2010 to 2013, Oudeman was a member of the Executive Committee of Akzo Nobel, responsible for HR and Organisational Development. Akzo Nobel is the world's largest paint and coatings company and major producer of specialty chemicals, with operations in more than 80 countries. Before joining Akzo Nobel, she was Executive Director Strip Products Division at Corus Group, now Tata Steel Europe. Oudeman has extensive experience as a line manager in the steel industry and considerable international business experience.
Education: Oudeman has a law degree from Rijksuniversiteit Groningen in the Netherlands and an MBA in business administration from the University of Rochester, New York, USA and Erasmus University, Rotterdam, the Netherlands.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Oudeman participated in eight ordinary board meetings, four extraordinary board meetings, six meetings of the compensation and executive development committee and one meeting of the board's safety, sustainability and ethics committee. Oudeman is a Dutch citizen and resident in the Netherlands.


Rebekka Glasser Herlofsen

Rebekka Glasser Herlofsen
Born: 1970
Position: Shareholder-elected member of the board and the board's audit committee.
Term of office: Member of the board of Statoil ASA since 19 March 2015 Up for election in 2016.
Independent: Yes
Other directorships: Member of the board of directors of DNV holding, DNV Foundation, DNV GL and member of the committee for tax and capital in the Norwegian Shipowners' Association.
Number of shares in Statoil ASA as of 31 December 2015: None
Loans from Statoil: None
Experience: Since 2012, Herlofsen has been the Chief Financial Officer in the Norwegian shipping company Torvald Klaveness. She has broad financial and strategic experience from several corporations and board directorships. Herlofsen's professional career began in the leading Nordic Investment Bank, Enskilda Securities, where she worked with corporate finance from 1995 to 1999 in Oslo and London. During the next ten years Herlofsen worked in the Norwegian shipping comp any Bergesen d.y. ASA (later BW Group). During her period with Bergesen d.y. ASA/BW Group Herlofsen held leading positions within M&A, strategy and corporate planning and was part of the group management team.
Education: MSc in Economics and Business Administration (Siviløkonom) and Certified Financial Analyst Program, the Norwegian School of Economics (NHH). Breakthrough Program for Top Executives at IMD business school, Switzerland.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Herlofsen participated in six ordinary board meetings, one extraordinary board meeting and four meetings of the audit committee. Herlofsen is a Norwegian citizen and resident in Norway.


Wenche Agerup

Wenche Agerup
Born: 1964
Position: Shareholder-elected member of the board, the board's compensation and executive development committee and the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA since 21 August 2015. Up for election in 2016.
Independent: No.
Pursuant to the NYSE rules, a director will not be considered independent under the NYSE rules if the director is, or was within the past three years, an executive officer of another company at which any of the listed company's current executive officers are, or were within the past three years, members of the compensation committee. This rule also applies to foreign listed companies. Agerup was a member of Norsk Hydro ASA's management team while Irene Rummelhoff, Executive Vice President of New Energy Solutions in Statoil, was member of the board's compensation committee in Norsk Hydro. Agerup is therefore deemed as a non-independent board member in Statoil for a period of three years from 31 December 2014, i.e. until 31 December 2017.
Other directorships: Agerup is a member of the board of the seismic company TGS ASA.
Number of shares in Statoil ASA as of 31 December 2015: 2,423
Loans from Statoil: None
Experience: Agerup is an Executive Vice President and the Chief Corporate Affairs Officer in Telenor ASA. Agerup was the Executive Vice President for Corporate Staffs and the General Counsel of Norsk Hydro ASA from 2010 to 31 December 2014. She has held various executive roles in Hydro since 1997, including within the company's M&A-activities, the business area Alumina, Bauxite and Energy, as a plant manager at Hydro's metal plant in Årdal and as a project director for a Joint Venture in Australia where Hydro cooperated with the Australian listed company UMC.
Education: MA in Law from the University of Oslo, Norway (1989) and a Master of Business Administration from Babson College, USA (1991).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Agerup participated in three ordinary board meetings, three meetings of the compensation and executive development committee and two meetings of the safety, sustainability and ethics committee. Agerup is a Norwegian citizen and resident in Norway.


Lill-Heidi Bakkerud

Lill-Heidi Bakkerud
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of Statoil ASA from 1998 to 2002, and again since 2004. Up for election in 2017.
Independent: No
Other directorships: Bakkerud is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this.
Number of shares in Statoil ASA as of 31 December 2015: 330
Loans from Statoil: None
Experience: Bakkerud has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is now a full-time employee representative as the leader of the union Industri Energi's Statoil branch.
Education: Bakkerud has a craft certificate as a process/chemistry worker.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2015, Bakkerud participated in eight ordinary board meetings, four extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Bakkerud is a Norwegian citizen and resident in Norway.

Ingrid Elisabeth di Valerio

Ingrid Elisabeth di Valerio
Born: 1964
Position: Employee-elected member of the board and member of the board's audit committee.
Term of office: Member of board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Board member of First Scandinavia, Montanus AS and member of Tekna's central nomination committee.
Number of shares held in Statoil ASA as of 31 December 2015: 2,845
Loans from Statoil: None
Experience: Di Valerio has been employed by Statoil since 2005, and works within materials discipline for Technology, Projects & Drilling. Di Valerio was the union Tekna's main representative in Statoil from 2008 to 2013. She also sat on Tekna's central committee from 2005 to 2013.
Education: Chartered engineer (mathematics and physics) from the Norwegian University of Science and Technology in Trondheim (NTNU).
Familiy relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2015, di Valerio participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the audit committee. Di Valerio is a Norwegian citizen and resident in Norway.

Stig Lægreid

Stig Lægreid
Born: 1963
Position: Employee-elected member of the board and member of the board's safety, sustainability and ethics committee.
Term of office: Member of the board of directors of Statoil ASA from 1 July 2013. Up for election in 2017.
Independent: No
Other directorships: Member of The Norwegian society for Engineers and Technologists' (NITO) negotiation committee for private sector.
Number of shares held in Statoil ASA as of 31 December 2015: 1,519
Loans from Statoil: None
Experience: Employed in ÅSV and Norsk Hydro since 1985. Mainly occupied as project engineer and constructor for production of primary metals until 2005 and from 2005 as weight estimator for platform design. He is now a full-time employee representative as the leader of the union NITO, Statoil.
Education: Bachelor degree, mechanical construction from OIH.
Family relations: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2015, Lægreid participated in eight ordinary board meetings, four extraordinary board meetings and five meetings of the safety, sustainability and ethics committee. Lægreid is a Norwegian citizen and resident in Norway.

In addition, there are four employee-elected deputy members of the board who attend board meetings in the event an employee-elected member of the board is unable to attend.

7.6.1 Audit committee

The board of directors elects at least three of its members to serve on the board of directors' audit committee and appoints one of them to act as chair. The employee-elected members of the board of directors may nominate one audit committee member.

At year-end 2015, the audit committee members were Jakob Stausholm (chair), Roy Franklin, Rebekka Herlofsen and Ingrid di Valerio (employee-elected board member).

The audit committee is a sub-committee of the board of directors, and its objective is to act as a preparatory body in connection with the board's supervisory roles with respect to financial reporting and the effectiveness of the company's internal control system. It also attends to other tasks assigned to it in accordance with the instructions for the audit committee adopted by the board of directors. The audit committee is instructed to assist the board of directors in its supervising of matters such as:

- Monitoring the financial reporting process, including oil and gas reserves, fraudulent issues and reviewing the implementation of accounting principles and policies
- Monitoring the effectiveness of the company's internal control, internal audit and risk management systems
- Maintaining continuous contact with the statutory auditor regarding the annual and consolidated accounts
- Reviewing and monitoring the independence of the company's internal auditor and the independence of the statutory auditor, reference is made to the Norwegian Auditors Act chapter 4, and, in particular, whether services other than audits provided by the statutory auditor or the audit firm are a threat to the statutory auditor's independence

The audit committee supervises implementation of and compliance with the group's Code of Conduct in relation to financial reporting.

The internal audit function reports directly to the board of directors and to the chief executive officer.

Under Norwegian law, the external auditor is appointed by the shareholders at the annual general meeting based on a proposal from the corporate assembly. The audit committee issues a statement to the annual general meeting relating to the proposal.

The audit committee meets at least five times a year, and it meets separately with the internal auditor and the external auditor on a regular basis.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors. The external auditors report directly to the audit committee on a regular basis.

The audit committee is tasked with ensuring that the company has procedures in place for receiving and dealing with complaints received by the company regarding accounting, internal control or auditing matters, and procedures for the confidential and anonymous submission, via the group's ethics helpline, by company employees of concerns regarding accounting or auditing matters, as well as other matters regarded as being in breach of the group's Code of Conduct, a material violation of an applicable US federal or state securities law, a material breach of fiduciary duties or a similar material violation of any other US or Norwegian statutory provision. The audit committee is designated as the company's qualified legal compliance committee for the purposes of section 307 of the Sarbanes-Oxley Act of 2002.

In the execution of its tasks, the audit committee may examine all activities and circumstances relating to the operations of the company. In this regard, the audit committee may request the chief executive officer or any other employee to grant it access to information, facilities and personnel and such assistance as it requests. The audit committee is authorised to carry out or instigate such investigations as it deems necessary in order to carry out its tasks and it may use the company's internal audit or investigation unit, the external auditor or other external advice and assistance. The costs of such work will be covered by the company.

The audit committee is only responsible to the board of directors for the execution of its tasks. The work of the audit committee in no way alters the responsibility of the board of directors and its individual members, and the board of directors retains full responsibility for the audit committee's tasks.

The audit committee held six meetings in 2015. There was 96.3% attendance at the committee's meetings.

The board of directors has decided that a member of the audit committee, Jakob Stausholm, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20-F. The board of directors has also concluded that Jakob Stausholm, Roy Franklin and Rebekka Herlofsen are independent within the meaning of Rule 10A-3 under the Securities Exchange Act.

The committee's mandate is available at Statoil.com/auditcommittee.

7.6.2 Compensation and executive development committee

The compensation and executive development committee is a sub-committee of the board of directors that assists the board in matters relating to management compensation and leadership development.

The main responsibilities of the compensation and executive development committee are:

(1) as a preparatory body for the board, to make recommendations to the board in all matters relating to principles and the framework for executive rewards, remuneration strategies and concepts, the CEO's contract and terms of employment, and leadership development, assessments and succession planning;

(2) to be informed about and advise the company's management in its work on Statoil's remuneration strategy for senior executive and in drawing up appropriate remuneration policies for senior executives; and

(3) to review Statoil's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of up to four board members. At year-end 2015, the committee members were Øystein Løseth (chair), Bjørn Tore Godal, Maria Johanna Oudeman and Wenche Agerup. All of the committee members are non-executive directors. All members, except for Wenche Agerup, are independent.

The committee held seven meetings in 2015 and attendance was 96%.

For a more detailed description of the objective and duties of the compensation committee, please see the instructions for the compensation committee available at Statoil.com/compensationcommittee.

7.6.3 Safety, sustainability and ethics committee

The safety, sustainability and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to safety, sustainability and ethics.

The safety, sustainability and ethics committee (the committee) is chaired by Roy Franklin and the other members are Bjørn Tore Godal, Wenche Agerup, Stig Lægreid (employee-elected board member) and Lill-Heidi Bakkerud (employee-elected board member).

In its business activities, Statoil is committed to comply with applicable laws and regulations and to act in an ethical, environmental, safe and socially responsible manner. The committee has been established to support our commitment in this regard, and it assists the board of directors in its supervision of the company's safety, sustainability and ethics policies, systems and principles with the exception of aspects related to "financial matters".

Establishing and maintaining a committee dedicated to safety, sustainability and ethics is intended to ensure that the board of directors has a strong focus on and knowledge of these complex, important and constantly evolving areas. The committee acts as a preparatory body for the board of directors and, among other things, monitors and assesses the effectiveness, development and implementation of policies, systems and principles in the areas of safety, sustainability and ethics, with the exception of aspects related to "financial matters".

The committee held five meetings in 2015, and attendance was 100%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the committee available at Statoil.com/ssecommittee.

7.7 Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo Børs, but Statoil is also registered as a foreign private issuer with the US Securities and Exchange Commission and listed on the New York Stock Exchange.

American Depositary Shares represent the company's ordinary shares listed on the New York Stock Exchange (NYSE). While Statoil's corporate governance practices follow the requirements of Norwegian law, Statoil is also subject to the NYSE's listing rules.

As a foreign private issuer, Statoil is exempted from most of the NYSE corporate governance standards that domestic US companies must comply with. However, Statoil is required to disclose any significant ways in which its corporate governance practices differ from those applicable to domestic US companies under the NYSE rules. A statement of differences is set out below:

Corporate governance guidelines

The NYSE rules require domestic US companies to adopt and disclose corporate governance guidelines. Statoil's corporate governance principles are developed by the management and the board of directors, in accordance with the Norwegian Code of Practice for Corporate Governance and applicable law. Oversight of the board of directors and management is exercised by the corporate assembly.

Director independence

The NYSE rules require domestic US companies to have a majority of "independent directors". The NYSE definition of an "independent director" sets out five specific tests of independence and also requires an affirmative determination by the board of directors that the director has no material relationship with the company.

Pursuant to Norwegian company law, Statoil's board of directors consists of members elected by shareholders and employees. Statoil's board of directors has determined that, in its judgment, all of the shareholder-elected directors, except one, are independent. In making its determinations of independence, the board focuses inter alia on there not being any conflicts of interest between shareholders, the board of directors and the company's management, but it does not explicitly make its determination based on the NYSE's five specific tests. The directors elected from among Statoil's employees would not be considered independent under the NYSE rules because they are employees of Statoil. None of the employee-elected directors is an executive officer of the company.

For further information about the board of directors see section 7.6 *Board of directors*.

Board committees

Pursuant to Norwegian company law, managing the company is the responsibility of the board of directors. Statoil has an audit committee, a safety, sustainability and ethics committee and a compensation and executive development committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation and executive development committee operate pursuant to charters that are broadly comparable to the form required by the NYSE rules. They report on a regular basis to, and are subject to, continuous oversight by the board of directors. For further information about the board's sub-committees, see sections 7.6.1 *Audit Committee,* 7.6.2 *Compensation and executive development committee and 7.6.3 Safety, sustainability and ethics committee.*

Statoil complies with the NYSE rule regarding the obligation to have an audit committee that meets the requirements of Rule 10A-3 of the US Securities Exchange Act of 1934.

As required by Norwegian company legislation, the members of Statoil's audit committee include an employee-elected director. Statoil relies on the exemption provided for in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the US Securities Exchange Act of 1934 with respect to the employee-elected director. Statoil does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees. The other members of the audit committee meet the independence requirements under Rule 10A-3.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

Statoil does not have a nominating/corporate governance sub-committee formed from its board of directors. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the nomination committee which is elected by the general meeting of shareholders. NYSE rules require the compensation committee of US companies to comprise independent directors under the NYSE rules, recommend senior management remuneration and make a determination on the independence of advisors when engaging them. Statoil, as foreign private issuer, is exempt from complying with these rules and is permitted to follow its home country regulations. Statoil considers all its compensation committee members to be independent, cf. the discussion on director independence above. Statoil's compensation committee makes recommendations to the board about management remuneration, including that of the CEO. The compensation committee assesses its own performance and has the authority to hire external advisors. The nomination committee, which is elected by the general meeting of shareholders, recommends to the corporate assembly the candidates and remuneration of the board of directors. Also, the nomination committee recommends to the general meeting of shareholders the candidates and remuneration of the corporate assembly and the nomination committee.

Shareholder approval of equity compensation plans

The NYSE rules require that, with limited exemptions, all equity compensation plans must be subject to a shareholder vote. Under Norwegian company law, although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders, the approval of equity compensation plans is normally reserved for the board of directors.

7.8 Management

The president and CEO has overall responsibility for day-to-day operations in Statoil and appoints the corporate executive committee (CEC). Each of the members of the CEC is head of a separate business area or staff function.

The president and CEO has overall responsibility for day-to-day operations in Statoil. The president and CEO is responsible for developing Statoil's business strategy and presenting it to the board of directors for decision, for the execution of the business strategy and for cultivating a performance-driven, value-based culture.

The president and CEO appoints the corporate executive committee. Members of the CEC have a collective duty to safeguard and promote Statoil's corporate interests and to provide the president and CEO with the best possible basis for deciding the company's direction, making decisions and executing and following up business activities. In addition, each of the CEC members is head of a separate business area or staff function.

Members of Statoil's corporate executive committee as of 31 December 2015:

Eldar Sætre, President and CEO

Eldar Sætre
Born: 1956
Position: President and chief executive officer of Statoil ASA since 15 October 2014.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2015: 39,130
Loans from Statoil: None
Experience: Sætre joined Statoil in 1980. Executive vice president and CFO from October 2003 until December 2010. Executive vice president for Marketing, Midstream and Processing (MMP) from 2011 until 2014.
Education: MA in business economics from the Norwegian School of Economics and Business Administration (NHH) in Bergen.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Sætre is a Norwegian citizen and resident in Norway.

Hans Jakob Hegge, Chief financial officer (CFO)

Hans Jakob Hegge
Born: 1969
Position: Executive vice president and chief financial officer (CFO) of Statoil ASA since 1 August 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 22,854
Loans from Statoil: None
Experience: Hegge has held several managerial positions in Statoil, including Senior Vice President (SVP) for Operations North in Development and Production Norway (DPN) (2013-2015), SVP for Operations East (2011-2013) in DPN, SVP for Operational Development in DPN (2009-2011) and SVP for Global Business Services in Chief Financial Officer area (CFO) (2005-2009). From 1995 to 2004 he held various positions in DPN, Natural Gas business area and corporate functions in Statoil.
Education: Master of Science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Hegge is a Norwegian citizen and resident in Norway.

Anders Opedal, Chief operating officer (COO)

Anders Opedal
Born: 1968
Position: Executive vice president and chief operating officer (COO) of Statoil ASA since 1 April 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 14,511
Loans from Statoil: None
Experience: Opedal joined Statoil in 1997 as a petroleum engineer in the Statfjord operations. He has held a range of positions in Drilling and well, Procurement and projects. In 2011 Opedal took on the role as Senior Vice President for Projects in Technology, Projects and Drilling (TPD) responsible for Statoil's approximately NOK 300 billion project portfolio. Before joining Statoil, Opedal worked for Schlumberger and Baker Hughes.
Education: MBA from Heriot-Watt University and an engineering degree from NTH.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Opedal is a Norwegian citizen and resident in Norway.


Lars Christian Bacher, Executive vice president Development and Production International (DPI)

Lars Christian Bacher
Born: 1964
Position: Executive vice president of Statoil ASA since 1 September 2012.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 21,116
Loans from Statoil ASA: None
Experience: Bacher joined Statoil in 1991 and has held a number of leading positions in Statoil, including that of platform manager on the Norne and Statfjord fields on the Norwegian continental shelf. He was in charge of the merger process involving the offshore installations of Norsk Hydro and Statoil. Bacher has also been senior vice president for Gullfaks operations and subsequently for the Tampen area. His most recent position, which he held from September 2009, was as senior vice president for Statoil's Canadian operations in Development & Production USA (DPUSA).
Education: Master of science in chemical engineering from the Norwegian Institute of Technology (NTH). He also holds a master's degree in finance from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the corporate executive committee, the board of directors or the corporate assembly.
Other matters: Bacher is a Norwegian citizen and resident in Norway.


Torgrim Reitan, Executive vice president Development and Production USA (DPUSA)

Torgrim Reitan
Born: 1969
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 28,482
Loans from Statoil: None
Experience: From 1 January 2011 to 1 August 2015 Reitan held the position as executive vice president and chief financial officer of Statoil (CFO). He has held several managerial positions in Statoil, including senior vice president (SVP) in trading and operations in the Natural Gas business area (2009 - 2010), SVP in performance management and analysis (2007 - 2009) and SVP in performance management, tax and M&A (2005 - 2007). From 1995 to 2004, Reitan held various positions in the Natural Gas business area and corporate functions in Statoil.
Education: Master of science degree from the Norwegian School of Economics and Business Administration (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Reitan is a Norwegian citizen and resident in the United States.


John Knight, Executive vice president Global Strategy and Business Development (GSB)

John Knight
Born: 1958
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: Member on the advisory board of the Columbia University Center on Global Energy Policy in New York. Chair of ONS16 Conference Committee in Stavanger, Norway and member on the advisory board of Imperial College Business School MsC Climate Change Management and Finance in London.
Numbers of shares in Statoil ASA as of 31 December 2015: 85,731
Loans from Statoil ASA: None
Experience: Knight held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, Knight held various positions in energy investment banking. From 1977 to 1987, he qualified and worked as a barrister/lawyer, and was employed by Shell Petroleum in London during the period 1985-1987.
Education: Knight has first and post-graduate degrees in law from Cambridge University and the Inns of Court School of Law in London.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Knight is a British citizen and resident in England.


Tim Dodson. Executive vice president, Exploration (EXP)

Tim Dodson
Born: 1959
Position: Executive vice president of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 28,614
Loans from Statoil ASA: None
Experience: Dodson has worked in Statoil since 1985 and held central management positions in the company, including the positions of senior vice president for global exploration, Exploration & Production Norway and the technology arena.
Education: Master of science in geology and geography from the University of Keele.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Dodson is a British citizen and resident in Norway.


Margareth Øvrum. Executive vice president Technology, Projects and Drilling (TPD)

Margareth Øvrum
Born: 1958
Position: Executive vice president of Statoil ASA since September 2004.
External offices: Member of the board of Atlas Copco AB (Sweden) and Alfa Laval (Sweden).
Number of shares in Statoil ASA as of 31 December 2015: 42,621
Loans from Statoil: None
Experience: Øvrum has worked for Statoil since 1982 and has held central management positions in the company, including the position of executive vice president for health, safety and the environment and executive vice president for Technology & Projects. Øvrum was the company's first female platform manager, on the Gullfaks field. She was senior vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf.
Education: Master's degree in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Øvrum is a Norwegian citizen and resident in Norway.


Arne Sigve Nylund, Executive vice president Development and production Norway (DPN)

Arne Sigve Nylund
Born: 1960
Position: Executive vice president of Statoil ASA since 1 January 2014.
External offices: Member of the board of directors of The Norwegian Oil & Gas Association (Norsk Olje & Gass).
Number of shares in Statoil ASA as of 31 December 2015: 9,261
Loans from Statoil: None
Experience: Employed by Mobil Exploration Inc. from 1983-1987. Since 1987, Nylund has held several central management positions in Statoil ASA.
Education: Mechanical engineer from Stavanger College of Engineering with further qualifications in operational technology from Rogaland Regional College/University of Stavanger (UiS). Business graduate of the Norwegian School of Business and Management (NHH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Nylund is a Norwegian citizen and is resident in Norway.


Jens Økland, executive vice president Marketing, Midstream and Processing (MMP)

Jens Økland
Born: 1969
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: None
Number of shares in Statoil ASA as of 31 December 2015: 10,735
Loans from Statoil ASA: None
Experience: Økland joined Statoil in 1994 and has mainly worked in the midstream and downstream sectors. Before becoming executive vice president of MMP, Økland worked as vice president of operations for the Åsgard area in Development and Production Norway. Åsgard ranks among the largest developments on the Norwegian continental shelf, supplying about 11 billion cubic metres of gas annually to Europe. Previously Økland was senior vice president of Statoil's natural gas portfolio and supply business in North America, marketing and developing infrastructure solutions for equity and non-equity production. Before heading up Statoil's downstream gas division in North America, he had senior marketing and business development positions within natural gas in Europe mainly focusing on Germany, Statoil's largest gas market.
Education: MSc in business from BI Norwegian Business School.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Økland is a Norwegian citizen and resident in Norway.


Irene Rummelhoff, executive vice president New Energy Solutions (NES)

Irene Rummelhoff
Born: 1967
Position: Executive vice president of Statoil ASA since 1 June 2015.
External offices: Member of the board of directors of Norsk Hydro ASA.
Number of shares in Statoil ASA as of 31 December 2015: 17,082
Loans from Statoil ASA: None
Experience: Rummehoff joined Statoil in 1991. She has held a number of management positions within international business development, exploration, and the downstream business in Statoil.
Education: Master's degree in petroleum geosciences from the Norwegian Institute of Technology (NTH).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Rummehoff is a Norwegian citizen and resident in Norway.

Statoil has granted loans to the Statoil-employed spouse of certain of the Executive Vice Presidents as part of its general loan arrangement for Statoil employees. Employees in salary grade 12 or higher may take out a car loan from Statoil in accordance with standardised provisions set by the company. The standard maximum car loan is limited to the cost of the car, including registration fees, but not exceeding NOK 300,000. Employees outside the collective labour area are entitled to a car loan up to NOK 575,000 (vice presidents and senior vice presidents) or NOK 475,000 (other positions). The car loan is interest-free, but the tax value, "interest advantage", must be reported as salary. Permanent employees in Statoil ASA may also apply for a consumer loan up to NOK 300.000. The interest rate on consumer loans is corresponding to the standard rate in effect at any time for "reasonable loans" from employer as decided by the Norwegian Ministry of Finance, i.e. the lowest rate an employer may offer without triggering taxation of the advantage for the employee.

7.9 Compensation to governing bodies

This section describes the compensation to the board of directors, the corporate executive committee and the corporate assembly.

In 2015, the aggregate compensation to the corporate assembly was NOK 1,047,143, to the members of the board of directors NOK 5,950,035 and to the members of the corporate executive committee NOK 87,763,000 (all in rounded figures).

The members of the corporate assembly and the board of directors have an annual, fixed remuneration, except for deputy members who receive remuneration per meeting. In addition, board members resident outside of Scandinavia or outside of Europe receive additional travel fees (based on two different travel fee rates) per board meeting attended. The shareholder-elected and employee-elected members of the corporate assembly and the board are entitled to the same remuneration rates.

Detailed information about the individual compensation to the members of the board of directors and members of the corporate executive committee in 2015 is provided in the tables below.

Members of the board (figures in NOK thousand)	Board of directors	Audit committee	Compensation and executive development committee	SSE committee	Total remuneration
Øystein Løseth[1)]	557	65	65	-	687
Svein Rennemo[2)]	357	-	53	-	410
Grace Reksten Skaugen[3)]	98	-	27	-	125
Jakob Stausholm	373	207	-	-	580
Bjørn Tore Godal	373	-	84	93	550
Lill Heidi Bakkerud	373	-	-	84	457
Maria Johanna Oudeman	503	-	84	-	587
Catherine Hughes[4)]	198	-	-	37	235
James Mulva[5)]	307	65	-	-	373
Stig Lægreid	373	-	-	84	457
Ingrid Elisabeth di Valerio	373	134	-	-	507
Roy Franklin[6)]	261	68	-	65	394
Wenche Agerup[7)]	138	-	31	31	200
Rebekka Glasser Herlofsen[8)]	296	91	-	-	387
Total	4,580	631	344	395	5,950

1) Chair of the board from 1 July 2015
2) Chair of the board until and including 30 June 2015 (resigned)
3) Deputy chair until and including 18 March 2015 (resigned)
4) Member until and including 15 April 2015 (resigned)
5) Member until and including 30 June 2015 (resigned)
6) Deputy chair from 1 July 2015
7) Member from 21 August 2015
8) Member from 19 March 2015

Members of corporate executive committee in 2015 (figures in NOK thousand)[1)]	Fixed remuneration			Annual variable pay[5)]	Taxable benefits	Taxable compensation	Non-taxable benefits in kind	Estimated pension cost[6)]	Estimated present value of pension obligation[7), 8)]
	Fixed pay[2)]	Cash allowance[3)]	LTI [4)]						
Eldar Sætre[9), 11)]	7,748	0	2,492	3,504	421	14,165	0	0	79,699
Hans Jakob Hegge[9)]	1,349	44	302	324	7	2,025	0	273	7,753
Torgrim Reitan[9), 10)]	1,881	0	0	1,022	337	3,239	0	979	12,727
Torgrim Reitan - CFO[9)]	1,890	0	761	0	117	2,769	0	0	0
Lars Christian Bacher	3,266	0	739	843	377	5,226	437	872	14,191
Timothy Dodson	3,695	0	803	789	148	5,435	321	1,109	33,022
Margareth Øvrum	3,805	0	867	1,241	152	6,066	127	0	48,435
Arne Sigve Nylund	3,345	0	725	1,352	146	5,568	0	833	28,586
Jens Økland[9)]	1,684	41	394	526	11	2,655	0	354	5,669
Tor Martin Anfinnsen[9)]	1,298	0	281	584	104	2,266	0	390	22,576
Irene Rummelhoff[9)]	1,563	38	365	395	11	2,371	0	386	7,585
Anders Opedal[9)]	2,323	44	544	761	11	3,682	0	547	7,540
William Maloney[8), 9)]	3,933	0	4,625	4,625	1,226	14,410	138	698	0
John Knight[2), 8)]	8,695	0	3,468	3,468	1,231	16,863	0	0	0

1) All figures in the table are presented on accrual basis.
2) Fixed pay consists of base salary, holiday allowance and other administrative benefits. John Knight's fixed pay also includes a cash supplement that replaces his defined contribution pension plan.
3) Cash allowance in lieu of pension accrual above 12 G (the base amount in the national insurance scheme).
4) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA. Members of the corporate executive committee employed by non-Norwegian subsidiaries have a LTI scheme deviating from the model used in the parent company. A net amount equivalent to the annual variable pay is used for purchasing Statoil shares.
5) Annual variable pay includes holiday allowance for corporate executive committee (CEC) members resident in Norway.
6) Estimated pension cost for CEC members under defined benefit plans (Eldar Sætre, Timothy Dodson, Margareth Øvrum, Arne Sigve Nylund and Tor Martin Anfinnsen) is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2014 and is recognised as pension cost in the statement of income for 2015. The other CEC members have defined contribution plans including notional contribution plans and the contributions in the reporting period are recognised as pension cost in the statement of income. Payroll tax is not included. For further information, see note 19 *Pensions*.
7) Torgrim Reitan, Lars Christian Bacher, Hans Jakob Hegge, Jens Økland, Irene Rummelhoff and Anders Opedal were transferred to a defined contribution plan from 1 April 2015. Paid-up policies and rights letters issued in 2015 related to the defined benefit plans as well as the notional contribution plans are included in the present value of pension obligation at 31 December 2015. Estimated present value of pension obligation for the rest of the members of CEC employed by Statoil ASA, are presented with the defined benefit obligation.
8) William Maloney and John Knight's remuneration is in local currency US Dollar and British Pound, respectively. For John Knight the figures in the table are presented in NOK, using average currency rates in 2015. For William Maloney the average currency rates for the period 1 January to 30 September 2015 are used. The change in currency rates during the year, such as strengthening of USD and GBP versus NOK, impacts the development from 2014 to 2015. William Maloney's variable compensation is paid in 2015.
9) Eldar Sætre resumed role as acting chief executive officer (CEO) from 15 October 2014 until 3 February 2015. The 4 February Eldar Sætre was appointed as CEO on a permanent basis. Tor Martin Anfinnsen acted as executive vice president for Marketing, Midstream and Processing (MMP) from 15 October 2014 until 31 May 2015. Jens Økland was appointed executive vice president for MMP from 1 June 2015. William Maloney resigned as executive vice president for Development and Production North America (DPNA) July 31 and was followed by Torgrim Reitan who started as executive vice president for Development and Production USA (DPUSA) 1 August 2015. Hans Jakob Hegge was appointed executive vice president and chief financial officer from 1. August 2015. Irene Rummelhoff was appointed executive vice president for the newly established business area New Energy Solutions (NES) on 1 June 2015. Anders Opedal was appointed on 1 April 2015 in the new position chief operating officer (COO).
10) Compensation and benefit including standard international assignment terms for Torgrim Reitan during his tenure as executive vice president in DPUSA, commencing 1 August 2015.
11) Fixed pay for Eldar Sætre includes fixed remuneration element of NOK 1 815 000 not included in pensionable salary

There are no loans from the company to members of the corporate executive committee.

Former chief executive officer Helge Lund has in 2015 paid back NOK 5 033 491 in LTI bonus received in 2012, 2013 and 2014. He has received compensations and benefits that amount to NOK 2.7 million in 2015. The amount is related to base salary for the period 1 January to 8 February 2015 and final settlement payments such as holiday allowance earned in 2014 and 2015.

Members of corporate executive committee in 2014 (figures in NOK thousand)[1)]	Fixed remuneration: Fixed pay[3)]	Fixed remuneration: LTI[6)]	Annual variable pay[7)]	Taxable benefits in kind	Taxable compensation	Non-taxable benefits in kind	Estimated pension cost[8)]	Estimated present value of pension obligation[4), 9)]
Helge Lund[4), 5), 9)]	5,640	2,165	-	249	8,054	199	6,008	73,944
Torgrim Reitan[9)]	3,283	761	1,066	126	5,237	-	879	16,339
Lars Christian Bacher[9)]	3,256	739	1,034	363	5,393	428	685	15,879
Timothy Dodson	3,496	803	1,124	175	5,597	313	1,343	32,689
Margareth Øvrum	3,779	867	1,457	250	6,352	98	1,349	48,701
Arne Sigve Nylund[5)]	2,984	725	1,421	108	5,239	-	773	26,646
Eldar Sætre - CEO[5)]	1,370	-	689	35	2,094	-	989	46,769
Eldar Sætre - MMP	2,685	858	901	143	4,588	-	-	-
Tor Martin Anfinnsen[5)]	817	-	239	90	1,147	-	234	22,196
William Maloney[2), 8)]	4,333	2,167	2,167	960	9,627	166	713	-
John Knight[2), 3)]	7,132	2,845	2,845	1,133	13,955	-	-	-

1) All figures in the table are presented on accrual basis.

2) William Maloney and John Knight's remuneration is in local currency US Dollar and British Pound, respectively. The figures in the table are presented in NOK, using average currency rates in 2014.

3) Fixed pay consist of base salary, holiday allowance and any other administrative benefits. The figures are presented on accrual basis. John Knight's fixed pay also includes a cash supplement that replaces his defined contribution pension plan in 2014.

4) Helge Lund resigned from his position as CEO of Statoil 15 October 2014. Helge Lund has received salary and benefits that amounts to NOK 1.8 million in 2014 after his resignation as chief executive officer, not included in the table above. The pension liability listed in the table above represents the estimated present value of his pension obligation as of 31 December 2014. In line with the company's LTI policy, resignation during the lock-in period is regarded as a non-fulfilment of the LTI obligations. Following his resignation Helge Lund was obliged to pay back to Statoil a total of NOK 5 033 491, calculated based on the value of the locked shares acquired under the LTI program.

5) Following Helge Lund's resignation, Eldar Sætre resumed role as acting CEO with immediate effect on 15 October 2014, and Tor Martin Anfinnsen replaced Eldar Sætre as acting executive vice president for Marketing, Midstream and Processing (MMP). Arne Sigve Nylund replaced Øystein Michelsen from January 2014.

6) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment. The LTI element is presented the year it is granted for the members of the corporate executive committee employed by Statoil ASA. Members of the corporate executive committee employed by non-Norwegian subsidiaries have a LTI scheme deviating from the model used in the parent company. A net amount equivalent to the annual variable pay is used for purchasing Statoil shares, and the figures are presented on accrual basis.

7) Annual variable pay includes holiday allowance, and is presented on accrual basis.

8) Estimated pension cost is calculated based on actuarial assumptions and pensionable salary (mainly base salary) at 31 December 2013 and is recognised as pension cost in the statement of income for 2014. Payroll tax is not included. William Maloney is employed by a non-Norwegian entity and his pension cost reflects the payment under the entity's defined contribution plan made in 2014.

9) Torgrim Reitan and Lars Christian Bacher was transferred to a defined contribution plan from 1 April 2015, and the Estimated present value of pension obligation per 31 December 2014 reflects this change. Estimated present value of pension obligation related to Helge Lund, Torgrim Reitan and Lars Christian Bacher, are based on the estimated value of paid-up policies and rights letters to be issued in 2015, related to Helge Lund's resignation and the termination of Torgrim Reitan and Lars Christian Bacher's defined benefit pension plan. Estimated present value of pension obligation for the rest of the members of the corporate executive committee employed by Statoil ASA, are presented with the defined benefit obligation.

1 Remuneration policy and concept for the accounting year 2016

Reference is made to the document "Statement on remuneration for Statoil's Corporate Executive Committee", which is available at www.statoil.com, for a detailed description of the remuneration and remuneration policy for executive management applicable for the years 2015 and 2016. The main elements of Statoil's executive remuneration are described in the paragraphs below.

1.1 Policy and principles

The board of directors has in 2015 decided to introduce several new elements to the company's executive remuneration concept. The revised governmental guidelines on executive remuneration as of 13 February 2015 ("2015 governmental guidelines") entailed adjustments with impact on the company's executive remuneration concept. Changes to the pension system and the long-term incentive scheme are implemented to align with the 2015 governmental guidelines on executive remuneration. In addition the company has initiated improvements to strengthen the link between executive remuneration and the company's overall performance and results.

The changes include:

- a cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway (currently 12 G[2])
- adjustment to the long-term incentive scheme (LTI)
- a company performance modifier
- a threshold for variable pay

These changes are described in section 1.2-1.5 below.
The company performance modifier is subject to approval by the 2016 annual general meeting (AGM) cf. section 5.

Other than described in this section, the company's established remuneration principles and concepts as described in previous years Statements on remuneration and other employment terms for Statoil's corporate executive committee will be continued in the accounting year 2016.

The remuneration concept is an integrated part of our values based performance framework. It has been designed to:

- reflect our global competitive market strategy and local market conditions
- strengthen the common interests of employees in the Statoil group and its shareholders
- be in accordance with statutory regulations and good corporate governance
- be fair, transparent and non-discriminatory
- equally reward and recognise "what" we deliver and "how" we deliver
- differentiate on the basis of responsibilities and performance
- reward both short- and long-term contributions and results

1.2 Cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway

In the White Paper no. 27 (2013- 2014) the Government announced changes to its policy relating to pension contribution in companies where the State has majority ownership. The State would no longer support pension contribution above 12 G. This policy change was manifested in 2015 governmental guidelines on executive remuneration. In order to align with the 2015 governmental guidelines, Statoil ASA has introduced a cap at 12 G for pension contribution for new members of the corporate executive committee appointed after the effective date of the 2015 governmental guidelines.

In lieu of pension contribution for income above 12 G, new internal members of the corporate executive committee will be eligible for compensation. The compensation level will be dependent on the candidate's pension terms and base salary level and will be in the range of 15 - 20% of his/her base salary.

1.3 Adjustments to the long-term incentive scheme in Statoil ASA

According to the 2015 governmental guidelines, the long-term incentive (LTI) scheme is defined as variable remuneration. Earlier this was part of the fixed remuneration and included in the basis for calculating the participants' annual variable pay. This practice will be discontinued with the effect from earning year 2016. The LTI scheme as variable remuneration will have a maximum annual grant at 30% of the participants' fixed remuneration c.f. section 1.6 below.

1.4 Threshold

The board of directors has decided to introduce a threshold in the reward concept as a pre-requisite for the payment of variable pay and grant of long-term incentive (LTI). The threshold will have effect on the long-term incentive grant in 2016 provided this is not impeded by obligations in individual agreements. From the earning year 2016 the threshold will be applied on annual variable pay payments in 2017 and onwards. The threshold is based on Statoil group's full-year adjusted earnings after tax, requiring that a minimum level of earnings must be achieved for any payments to be made. This minimum level has been set at USD 2 billion. Earnings between USD 2 and 3.3 will result in bonus payments reduced by 50%. Above USD 3.3 billion the threshold is fully achieved and variable pay payments are not affected. Prior to application of the threshold an assessment of the company's overall performance in relation to the adjusted earnings results shall be made by the board of directors based on recommendations by the board compensation and executive development committee.

1.5 Company performance modifier

Subject to approval by the 2016 annual general meeting, a company performance modifier is introduced in the calculations for variable pay schemes from 2016 with subsequent impact on variable pay from 2017 onwards. The company performance modifier determines the proportion of the bonus factor that

[2] *The base amount in the Norwegian national insurance scheme, currently NOK 90,068*

will be paid, ranging from 50% to 150%. Company performance is assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE).

1.6 The remuneration concept for the corporate executive committee

Statoil's remuneration concept for the corporate executive committee consists of the following main elements:

- Fixed remuneration (base salary) and as applicable cash compensation
- Variable pay (annual variable pay (AVP) and long-term Incentive (LTI))
- Benefits (primarily pension, insurance and share savings plan)

Fixed remuneration consists of base salary, and as applicable cash compensation. The cash compensation is applied in lieu of pension contribution above 12 G as described in section 1.2 above or as a fixed remuneration to be competitive in the market.

The variable pay elements for members of the corporate executive committee in the parent company are:

- annual variable pay scheme which has a maximum potential of 50% of fixed remuneration
- LTI scheme with a maximum grant of 30% of fixed remuneration. The LTI grant level is differentiated related to position level. The obligation to invest the net LTI amount in Statoil shares and keep for a lock in period of 3 years will be continued.

The annual variable pay will be subject to the company performance modifier ref. section 1.5 above. Irrespective of the performance modifier results, the annual variable pay will have a maximum at 50% of the fixed remuneration.

The main benefit programmes applicable to senior executives are the general pension scheme, the insurance scheme and the employee share savings plan. In 2015 Statoil implemented a defined contribution scheme as the new general pension scheme. With the exception of employees who were 15 years or less from regular retirement age at 31th December 2014, all employees have been transferred to the new scheme. The employees exempted from transfer will retain the defined benefit scheme.

Deviations from the general principles outlined below pertaining to one current member and one former member of the corporate executive committee, implemented with effect as of 1 January 2011, are described in the statement on executive remuneration. These deviations have also been described in previous statements on remuneration and other employment terms for Statoil's corporate executive committee.

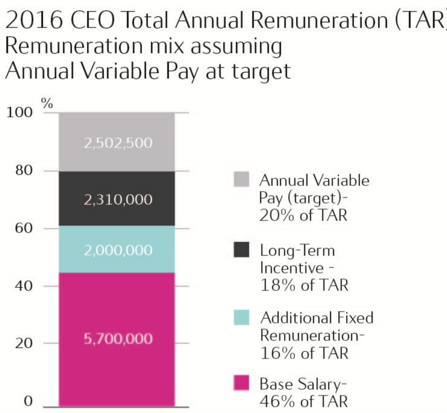
The main elements of Statoil's executive remuneration are described in more detail in the table below.

Main Elements - Statoil Executive Remuneration			
Remuneration Element	**Objective**	**Award level**	**Performance criteria**
Base Salary	Attract and retain the right high-performing individuals providing competitive but not market-leading terms.	We offer base salary levels which are aligned with the individual's responsibility and performance at a level which is competitive in the markets in which we operate.	The evaluation of performance is based on the fulfilment of pre-defined goals; see element Annual Variable Pay below. The base salary is normally subject to annual review.
Long-Term Incentive (LTI)	Strengthen the alignment of top management and shareholder interests and retention of key employees.	The LTI system is a, monetary compensation calculated as a portion of the participant's base salary; with a maximum annual grant at 30% of fixed remuneration. On behalf of the participant, the company acquires shares equivalent to the net annual amount. The grant is subject to a three year lock-in period and then released for the participant's disposal. Deviations applicable for executive vice presidents employed outside the parent company are described in the statement on executive remuneration. The threshold principles will apply for the annual grant.	In Statoil ASA, LTI is a variable remuneration element, Participation in the LTI scheme and the size of the annual LTI element are reflective of the level and impact of the position and not directly linked to the incumbent's performance.
Annual Variable Pay	Drive and reward individuals for annual achievement of business objectives and how results are delivered. Ensure link between individual variable pay and company's overall financial performance.	Members of the corporate executive committee are entitled to an annual variable pay ranging from 0-50% of their fixed remuneration. Target value is 25% (target value reflects fully satisfactory goal achievement). Deviations applicable for members of the corporate executive committee employed outside the parent company are described in the statement on executive remuneration. The deviation will in 2016 apply for one executive vice president employed by Statoil Global Employment Company Ltd. in London. The threshold principles and the company modifier (subject to AGM approval) will apply.	Achievement of annual performance goals (how and what to deliver), in order to create long-term and sustainable shareholder value. Assessment of goals related to selected KPI's from the balanced scorecard will impact the variable remuneration for the members of the corporate executive committee.
Pension & Insurance Schemes	Provide competitive postemployment and other benefits.	The general occupational pension plan is a defined contribution scheme with a contribution level of 7%/22% below/above 7,1 G. The defined benefit scheme will be retained by a grandfathered group of employees. The benefit scheme has a pension level amounting to 66 per cent of the pensionable salary conditional on a minimum of 30 years of service. Pension from the national insurance scheme is taken into account when estimating the pension. In order to draw a full pension from Statoil's defined benefit scheme the employment with the company needs to be maintained until the pensionable age. For new internal members of the corporate executive committee a cap for pension contribution at 12 G is established.	N/A
Employee Share Savings Plan	Align and strengthen employee and shareholder interests and remunerate for long term commitment and value creation.	Offer to purchase Statoil shares in the market limited to 5% of annual base salary.	If shares are kept for two calendar years of continued employment, the participants will be allocated bonus shares proportionate to their purchase.

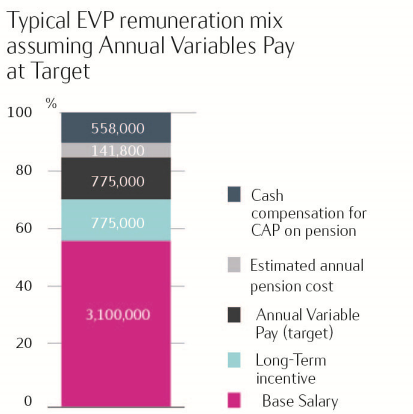
1.7. Base salary and remuneration mix 2016

Due to the current challenges facing our industry with falling oil and gas prices, decreasing margins and unsustainable cost levels, a salary freeze will be implemented for members of the corporate executive committee and other leaders and senior professionals in 2016.

The graphs below illustrate the chief executive officer's remuneration mix for 2016 and a typical remuneration mix for executive vice presidents. The chief executive officer's total remuneration package includes an additional fixed remuneration element compared to the executive vice presidents, and the executive vice presidents remuneration package includes, as applicable, a cash compensation in lieu of pension contribution above 12 G due to the implemented cap, see section 1.2 *Cap on pension contribution at the maximum limit in the tax-favoured joint pension schemes in Norway* above; please see further details of the chief executive officer's terms and conditions in section 1.11 *Terms and conditions for president and chief executive officer, Eldar*



Fixed Remuneration	Base Salary - 46% of TAR	5,700,000
	Additonal Fixed Remuneration	2,000,000
	Long-Term Incentive 18% of TAR	2,310,000
Variable pay	Annual Variable Pay (target)	2,502,500
Total		12,512,500



Fixed Remuneration	Base Salary	3,100,000
	Long-Term Incentive	775,000
Variable pay	Annual Variable Pay (target)	775,000
Pension	Estimated annual pension cost	141,800
Fixed Remuneration	Cash cimpensation for CAP on pension	558,000
		5,349,800

Figure 1: Illustrates chief executive officer remuneration mix for 2016. CEO's pension was fully accrued by 31 December 2014.
Figure 2: Illustrates an example of a typical remuneration mix for an executive vice president in Statoil with a cap on pension contribution.

1.8. Pension and insurance schemes

Members of the corporate executive committee are part of the general pension scheme in Statoil ASA. The chief executive officer and three executive vice presidents have individual early retirement pension agreement with the company.

The chief executive officer and one of the executive vice presidents have individual pension terms according to a previous standard arrangement implemented in October 2006. Subject to specific terms those executives are entitled to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. When calculating the number of years of membership in Statoil's general pension plan, these agreements grant the right to an extra contribution time corresponding to half a year of extra membership for each year the individual has served as executive vice president.

In addition, two members of the corporate executive committee have individually agreed retirement age of 65 and an early retirement pension level amounting to 66% of pensionable salary.

The individual pension terms for executive vice presidents outlined above are results of commitments according to previous established agreements.

Following a board decision 7 February 2012, the company's standard pension arrangements for executive vice presidents deviating from Statoil ASA's general pension plan have been discontinued and have not been applied for new appointments to the corporate executive committee.

As described in section 1.2, a cap on pension contribution for income above 12 G was in 2015 implemented for new members of the Corporate Executive Committee. The cap is applied to four executives vice presidents appointed after 13 February 2015.

Members of the corporate executive committee appointed before 13 February 2015, will maintain their pension contribution above 12 G based on obligations in established agreements.

Pension accruals for pensionable salary above 12 G are recognised as an unfunded defined benefit pension plan, i.e. not funded in a separate legal entity.

In addition to the pension benefits outlined above, the executive vice presidents in the parent company are offered disability and dependents' benefits in accordance with Statoil's general pension plan. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

1.9. Severance pay arrangements

The chief executive officer and the executive vice presidents are entitled to a severance payment equivalent to six months' salary, commencing at the time of expiry of a six months' notice period, when the resignation is at the request from the company. The same amount of severance payment is also payable if the parties agree that the employment should be discontinued and the executive vice president gives notice pursuant to a written agreement with the company. Any other payment earned by the executive vice president during the period of severance payment will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

The entitlement to severance payment is conditional on the chief executive officer or the executive vice president not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

As a general rule, the chief executive officer's/executive vice president's own notice will not instigate any severance payment.

1.10. Other benefits

Statoil has a share savings plan available to all employees including members of the corporate executive committee. The share savings plan entails an offer to purchase Statoil shares in the market limited to five per cent of annual gross salary. If the shares are kept for two full calendar years of continued employment the employees will be allocated bonus shares proportionate to their purchase. Shares to be used for sale and transfer to employees are acquired by Statoil in the market, in accordance with the authorisation from the annual general meeting.

The members of the corporate executive committee have benefits in kind such as company car and electronic communication.

1.11. Terms and conditions for president and chief executive officer, Eldar Sætre

Effective 4 February 2015 Statoil's board of directors appointed Eldar Sætre as president and chief executive officer of Statoil, following an acting period since 15 October 2014. The chief executive officer's annual base salary is NOK 5,700,000. Furthermore, the CEO is entitled to an additional fixed remuneration element of NOK 2,000,000 not included in the pensionable income.

The chief executive officer will participate in an annual variable pay scheme with a target level of 25%, and participation to the Company's 2016 LTI scheme with a value of 30% (gross) of base salary. The pension terms remain unchanged according to previously established pension agreement, as described in section 1.8 above.

2. Performance management, assessment and results essential for variable pay

2.1. Performance management, assessment and results essential for variable pay for 2015

Individual salary and annual variable pay reviews are based on the performance evaluation in our performance management system.

Performance is evaluated in two dimensions; "What" we deliver and "How" we deliver. Goals on "How" we deliver are based on our core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals.

"What" we deliver (business delivery) is defined through the company's performance framework "Ambition to Action", which addresses strategic objectives, key performance Indicators (KPIs) and actions across the five perspectives; Safety, Security and Sustainability, People and Leadership, Operations, Market and Results. Generally, Statoil believes in setting ambitious targets to inspire and drive strong performance.

In 2015, the main objectives and KPIs for each perspective were as outlined below. Each perspective was in addition supported by comprehensive plans and actions. It is only the KPI's for Results that will affect variable remuneration for members of the corporate executive committee.

Strategic objectives		2015 assessment
Safety, Security and Sustainability	The strategic objectives and actions address security and sustainability (Safety - see the Results perspective below)	There were no serious well incidents, whereas the number of oil and gas leakages was above target. Total CO_2 reduction was better than targeted and future ambitions have been increased.
People and organisation	The strategic objectives and actions address high performing leaders and teams, and global and cost-effective capabilities	Employee engagement increased from 2014, during a time with extensive organisational efficiency programmes. Leadership renewal across the organisation was better than targeted.
Operations	The strategic objectives and actions address reliable and cost-efficient operations, and value-driven technology development.	Production came in well above target, partly driven by continued improvements in production efficiency and optimised gas production from our flexible gas fields. Unit production cost is now the lowest among industry peers. Unit finding cost increased due to lower than expected exploration results.
Market	The strategic objectives and actions address stakeholder trust, value chain optimisation and portfolio and project management.	The organic Reserve Replacement Ratio (RRR) ended somewhat below the target of 1, while total RRR was well below due to divestments and a number of projects being postponed to maintain financial flexibility and improve project profitability. Project cost efficiency versus peers continued to improve.
Results	The strategic objectives and actions address shareholder return, financial robustness, value creation from exploration, cost & capital discipline and for 2015 also Safety.	Relative Total Shareholder Return (TSR) improved and ended on 6th against an industry peer group of 12. Relative RoACE also ended 6th but fell as a result of high exposure to upstream margins. Capex ended well below initially guided levels. The cash flow improvement programme delivered well above target. The serious incident frequency of 0,6 was unchanged from 2014.

Board assessment of the chief executive officer's performance
In its assessment of the chief executive officer's performance, and consequently his merit and annual pay for 2015, the board has put emphasis on the solid delivery on the cashflow improvement programme as well as CAPEX reductions and TSR. Serious incident frequency also continues to improve from 2014.

Before final conclusions of the performance assessments are drawn, sound judgement and hindsight information are applied. Measured KPI results are reviewed against their strategic contribution, sustainability and significant changes in assumptions.

This balanced approach, which involves a broad set of goals defined in relation to both "What" and "How" dimensions and an overall performance evaluation, is viewed to significantly reduce the likelihood that remuneration policies may stimulate excessive risk-taking or have other material adverse effects.

2.2 Key performance indicators for the chief executive officer for 2016

For the accounting year 2016 the CEO's variable remuneration for 2016 and base salary merit increase as of 1 January 2017 will be based on assessment of results on the following KIPs:

Safety, Security and Sustainability

- CO_2 intensity for the upstream portfolio
- Serious Incident Frequency (actual)

Market

- Capex (capital expenditure)

Results

- Relative Total Shareholder Return
- Relative RoACE
- Cash flow improvement programme

3. Execution of the remuneration policy and principles in 2015

3.1 Deviations from the governmental guidelines on variable compensation 2015

Two members of the executive committee had in 2015 variable pay schemes deviating from the description in section 1.6 above. One of the executives was employed by Statoil Gulf Services LLC in Houston and resigned from the company 31 July 2015. He was entitled to a variable pay scheme with a maximum of 100% for AVP and LTI, respectively. The other is still employed by Statoil Global Employment Company Ltd. in London and his variable pay scheme entail a framework for variable pay of 75% of his base salary for each of the elements annual variable pay and LTI, and is performance based. His contract also includes a provision for severance payment of 12 months' base salary.

The board's overall assessment is that the extended framework implemented with effect from 1 January 2011 for the variable pay schemes for these executives is necessary due to local market conditions, but not market leading for positions at this level at the respective locations.

3.2 Changes to the Corporate Executive Committee in 2015

In addition to the appointment of Eldar Sætre as president and chief executive officer, several changes have in 2015 been implemented to the organisational structure and the composition of the corporate executive committee. A new corporate staff and support function, chief operating officer (COO), was established from 1 April 2015, and Anders Opedal was appointed as executive vice president and COO.

New energy Solution (NES) was established as a new business area 1 June 2015 with Irene Rummelhoff as the executive vice president. Jens Økland was appointed executive vice president in MMP from 1 June 2015 succeeding Tor Martin Anfinnsen's acting period.

William Maloney, executive vice president Development and Production North America (DPNA), resigned from the company 31 July 2015. An adjustment to the DPNA organisation is implemented and this business area is renamed to Development and Production USA (DPUSA) [3]. Torgrim Reitan assumed responsibility as executive vice president in DPUSA as of 1 August 2015. Hans Jakob Hegge succeeded Torgrim Reitan as CFO from 1 august 2015.

3.3 Changes to individual terms in 2015

Following former president and chief executive officer Helge Lund's resignation a termination agreement was entered into. Helge Lund's termination date was 9 February 2015. Helge Lund received base salary and benefits compensation up until this date. He did not receive variable pay for the performance year 2014. The LTI scheme and share savings plan was closed in accordance with the company policy, and a repayment of NOK 5,033,491 was made by Helge Lund to Statoil ASA according to the LTI agreement. The company issued a paid-up policy and pension right letters for his pension accruals, in accordance with his individual pension agreement.

4. The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and the determination of salaries and other remuneration for corporate executive committee, are in accordance with the provisions of the Norwegian public limited liability companies act sections 5-6 and 6-16 a and the board's rules of procedure. The board's rules of procedure are available at www.statoil.com/board.

The board of directors has appointed a designated compensation and executive development committee. The compensation and executive development committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for Statoil's chief executive officer and the main principles and strategy for the remuneration and leadership development of our senior executives. The board of directors determines the chief executive officer's salary and other terms of employment.

The compensation and executive development committee answers to the board of Statoil ASA for the performance of its duties. The work of the committee in no way alters the responsibilities of the board of directors or the individual board members.

For further details about the roles and responsibilities of the compensation and executive development committee, please refer to the committee's instructions available at www.statoil.com/compensationcommittee.

5. Company performance modifier

Introduction

It is recommended to introduce a company performance modifier to be applied in calculation of variable pay. The relative total shareholder return is recommended as one of the criteria in the company modifier. Thus, the case is submitted to the annual general meeting for approval, pursuant to the provisions in the Public Limited Companies Act § 5-6 third paragraph last sentence ref. § 6-16 a, first paragraph third sentence number 3.

Background

Statoil has implemented annual variable pay schemes (AVP) for members of the corporate executive committee. The schemes are described in section 1.6 of this statement. Other executives, managers and employees in defined professional positions are also eligible for individual variable pay according to the company's guidelines.

The company's current annual variable pay scheme is entirely based on the individual participants' performance. Statoil has not implemented a company performance modifier for the variable pay schemes. The prevalent trend in the market is to ensure that variable remuneration is aligned with the company's performance. The governmental guidelines on executive remuneration also underline that "there shall be a clear connection between the variable salary and the performance of the company."

Proposal

Based on this, it is proposed to strengthen the link between the company's overall financial results and the individual variable pay by introducing a company performance modifier. The company performance is planned to be assessed against two equally weighted measures: relative total shareholder return (TSR) and relative return on average capital employed (RoACE). TSR and RoACE have historically constituted important performance indicators at the company's scorecard and are currently also applied in the corporate performance management system.

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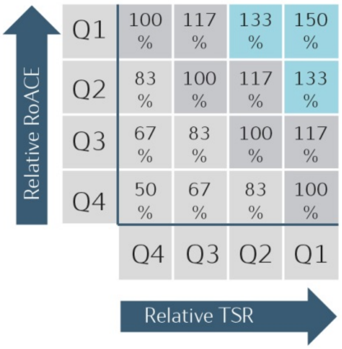
[3] *Transfer of responsibility for the company's business in Canada from Development and Production North America (DPNA) to Development and Production International (DPI)*

The results of both of these corporate performance measures are compared to our peers and our relative position determined. A position of first quartile means that Statoil is amongst the top scoring quartile of peer companies. A position of fourth quartile means Statoil is in the bottom performing quartile. In years with strong deliveries on relative TSR and RoACE, the matrix will result in the variable pay being modified with a factor higher than one and, correspondingly, lower than one in weak years. By applying relative numbers, the effect of fluctuating oil price will be reduced.

The combination of ratings for both measures, will act as a 'multiplier' according to the matrix displayed below.



The plan is to introduce the company performance modifier in calculation of annual variable pay for members of Statoil's corporate executive committee. Further application of the company performance modifier in Long-term incentive schemes will also be assessed and decided if deemed appropriate. In Long-term incentive schemes a three years average result for the modifier will typically be applied. The company also plan to implement the modifier in variable pay schemes for employees in positions below the corporate executive level.

The annual variable pay for members of the corporate executive committee will be within a framework of 50% of the fixed remuneration irrespective of the result of the modifier. Any deviations from this framework for members of the corporate executive committee will be explicitly explained in the board's annual Statements on remuneration and other employment terms for Statoil's corporate executive committee.

A complete statement on remuneration and other employment terms for Statoil's corporate executive committee is available at www.statoil.com.

7.10 Share ownership

This section describes the number of Statoil shares owned by the members of the board of directors, the corporate assembly and the corporate executive committee.

The number of Statoil shares owned by the members of the board of directors and the executive committee and/or owned by their close associates is shown below. Individually, each member of the board of directors and the corporate executive committee owned less than 1% of the outstanding Statoil shares.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2015	As of 8 March 2016
Members of the corporate executive committee		
Eldar Sætre	39,130	40,024
Hans Jakob Hegge	22,854	23,908
Anders Opedal	14,511	14,511
Lars Christian Bacher	21,116	22,308
Torgrim Reitan	28,482	29,435
John Knight	85,731	87,565
Tim Dodson	28,614	29,438
Margareth Øvrum	42,621	44,033
Arne Sigve Nylund	9,261	9,261
Jens Økland	10,735	11,386
Irene Rummelhoff	17,082	17,639
Members of the board of directors		
Øystein Løseth	1,000	1,000
Roy Franklin	0	0
Bjørn Tore Godal	0	0
Jakob Stausholm	50,000	50,000
Maria Johanna Oudeman	0	0
Rebekka Glasser Herlofsen	0	0
Wenche Agerup	2,423	2,423
Lill-Heidi Bakkerud	330	330
Ingrid Elisabeth di Valerio	2,845	3,165
Stig Lægreid	1,519	1,807

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2015 and as of 8 March 2016. In aggregate, members of the corporate assembly owned a total of 19,592 shares as of 31 December 2015 and a total of 22,157 shares as of 8 March 2016. Information about the individual share ownership of the members of the corporate assembly is presented in the section *Corporate governance - Corporate assembly*.

The voting rights of members of the board of directors, the corporate executive committee and the corporate assembly do not differ from those of ordinary shareholders.

7.11 Independent auditor

This section provides details about the independent auditor, the remuneration of the auditor and policies and procedures relating to the auditor.

Our independent registered public accounting firm (independent auditor) is independent in relation to Statoil and is elected by the general meeting of shareholders. The independent auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instructions for the board's audit committee approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

Every year, the independent auditor presents a plan to the audit committee for the execution of the independent auditor's work.

The independent auditor attends the meeting of the board of directors that deals with the preparation of the annual accounts.

The independent auditor participates in meetings of the audit committee.

When evaluating the independent auditor, emphasis is placed on the firm's qualifications, capacity, local and international availability and the size of the fee.

The audit committee evaluates and makes a recommendation to the board of directors, the corporate assembly and the general meeting of shareholders regarding the choice of independent auditor. The committee is responsible for ensuring that the independent auditor meets the requirements in Norway and in the countries where Statoil is listed. The independent auditor is subject to the provisions of US securities legislation, which stipulates that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee considers all reports from the independent auditor before they are considered by the board of directors. The audit committee holds regular meetings with the independent auditor without the company's management being present.

The audit committee's policies and procedures for pre-approval
In its instructions for the audit committee, the board of directors has delegated authority to the audit committee to pre-approve assignments to be performed by the independent auditor. Within this pre-approval, the audit committee has issued further guidelines. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the independent auditor.

All audit-related and other services provided by the independent auditor must be pre-approved by the audit committee. Provided that the types of services proposed are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services that are in accordance with policies established by the audit committee that specify in detail the types of services that qualify. It is a condition that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals can therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

Remuneration of the independent auditor in 2015
In the annual Consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and the fee for audit-related and other services. The chair presents the breakdown between the audit fee and the fee for audit-related and other services to the annual general meeting of shareholders.

The following table sets out the aggregate fees related to professional services rendered by Statoil's principal accountant KPMG AS, for the fiscal year 2015, 2014 and 2013.

Auditor's remuneration (in NOK million, excluding VAT)	For the year ended 31 December 2015	2014	2013
Audit fee	49	45	38
Audit related fee	14	8	8
Tax fee	0	0	0
Other service fee	0	0	0
Total	63	53	46

All fees included in the table were approved by the board's audit committee.

Audit fee is defined as the fee for standard audit work that must be performed every year in order to issue an opinion on Statoil's Consolidated financial statements, on Statoil's internal control over annual reporting and to issue reports on the statutory financial statements. It also includes other audit services, which are services that only the independent auditor can reasonably provide, such as the auditing of non-recurring transactions and the application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit-related fees include other assurance and related services provided by auditors, but not limited to those that can only reasonably be provided by the external auditor who signs the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements, such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

Other services fees include services provided by the auditors within the framework of the Sarbanes-Oxley Act, i.e. certain agreed procedures.

Of total increase in audit and audit related fees, NOK 3.2 million is due to currency effects, equivalent to 5%.

In addition to the figures in the table above, the audit fees and audit-related fees relating to Statoil operated licences paid to KPMG for the years 2015, 2014 and 2013 amounted to NOK 7 million, NOK 6 million and NOK 6 million, respectively.

7.12 Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures
The management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by the Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that these disclosure controls and procedures are effective at a reasonable level of assurance.

In order to facilitate the evaluation, the disclosure committee reviews material disclosures made by Statoil for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of investor relations, accounting and financial compliance, performance management and risk, tax and the general counsel and it may be supplemented by other internal and external personnel. The head of the internal audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that the management must necessarily exercise judgment when evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting
The management of Statoil ASA is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed, under the supervision of the chief executive officer and chief financial officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

The management has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the management has concluded that Statoil's internal control over financial reporting as of 31 December 2015 was effective.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of internal control over financial reporting as of 31 December 2015 has been audited by KPMG AS, an independent registered public accounting firm that also audits the Consolidated financial statements included in this annual report. Their audit report on the internal control over financial reporting is included in section 8 in the Consolidated financial statements in this report.

No changes occurred in our internal control over financial reporting during the period covered by Form 20-F that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We continuously make improvement to our internal control environment.

8 Consolidated financial statements Statoil

CONSOLIDATED STATEMENT OF INCOME

(in NOK billion)	Note	2015	2014	Full year 2013
Revenues		**465.3**	606.8	616.6
Net income from equity accounted investments		**(0.3)**	(0.3)	0.1
Other income	4	**17.8**	16.1	17.8
Total revenues and other income	3	**482.8**	622.7	634.5
Purchases [net of inventory variation]		**(211.2)**	(301.3)	(306.9)
Operating expenses		**(84.5)**	(72.9)	(74.1)
Selling, general and administrative expenses		**(7.5)**	(7.3)	(7.8)
Depreciation, amortisation and net impairment losses	11, 12	**(133.8)**	(101.4)	(72.4)
Exploration expenses	12	**(31.0)**	(30.3)	(18.0)
Net operating income	3	**14.9**	109.5	155.5
Net financial items	8	**(10.6)**	(0.0)	(17.0)
Income before tax		**4.3**	109.4	138.4
Income tax	9	**(41.6)**	(87.4)	(99.2)
Net income		**(37.3)**	22.0	39.2
Attributable to equity holders of the company		**(37.5)**	21.9	39.9
Attributable to non-controlling interests		**0.2**	0.1	(0.6)
Basic earnings per share (in NOK)	10	**(11.80)**	6.89	12.53
Diluted earnings per share (in NOK)	10	**(11.80)**	6.87	12.50

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK billion)	Note	2015	2014	Full year 2013
Net income		(37.3)	22.0	39.2
Actuarial gains (losses) on defined benefit pension plans	19	10.1	(0.0)	(5.9)
Income tax effect on income and expense recognised in OCI		(2.8)	0.9	1.5
Items that will not be reclassified to the Consolidated statement of income		7.3	0.9	(4.4)
Currency translation adjustments[1)]		27.4	41.6	22.9
Items that may be subsequently reclassified to the Consolidated statement of income		27.4	41.6	22.9
Other comprehensive income		34.7	42.5	18.5
Total comprehensive income		(2.6)	64.5	57.7
Attributable to the equity holders of the company		(2.8)	64.4	58.3
Attributable to non-controlling interests		0.2	0.1	(0.6)

1) Currency translation adjustments of NOK 27.4 billion in 2015 are net of accumulated currency translation gains of NOK 3.3 billion reclassified to the Consolidated statement of income related to the sale of interests in the Shah Deniz project, the South Caucasus Pipeline and the Trans Adriatic Pipeline AG. See note 4 *Acquisitions and dispositions*.

CONSOLIDATED BALANCE SHEET

(in NOK billion)	Note	At 31 December 2015	2014
ASSETS			
Property, plant and equipment	11	546.2	562.1
Intangible assets	12	83.3	85.2
Equity accounted investments		7.3	8.4
Deferred tax assets	9	17.8	12.9
Pension assets	19	11.3	8.0
Derivative financial instruments	25	23.8	29.9
Financial investments	13	20.6	19.6
Prepayments and financial receivables	13	8.5	5.7
Total non-current assets		718.7	731.7
Inventories	14	22.0	23.7
Trade and other receivables	15	58.8	83.3
Derivative financial instruments	25	4.8	5.3
Financial investments	13	86.5	59.2
Cash and cash equivalents	16	76.0	83.1
Total current assets		248.0	254.8
Total assets		966.7	986.4
EQUITY AND LIABILITIES			
Shareholders' equity		354.7	380.8
Non-controlling interests		0.3	0.4
Total equity	17	355.1	381.2
Finance debt	18, 22	264.0	205.1
Deferred tax liabilities	9	65.4	71.5
Pension liabilities	19	26.2	27.9
Provisions	20	109.4	117.2
Derivative financial instruments	25	11.3	4.5
Total non-current liabilities		476.3	426.2
Trade and other payables	21	82.2	100.7
Current tax payable		24.1	39.6
Finance debt	18	20.5	26.5
Dividends payable	17	6.2	5.7
Derivative financial instruments	25	2.3	6.6
Total current liabilities		135.3	179.0
Total liabilities		611.7	605.2
Total equity and liabilities		966.7	986.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK billion)	Share capital	Additional paid-in capital	Retained earnings	Currency translation adjustments	Shareholders' equity	Non-controlling interests	Total equity
At 31 December 2012	8.0	40.6	270.8	(0.2)	319.2	0.7	319.9
Net income for the period			39.9		39.9	(0.6)	39.2
Other comprehensive income			(4.4)	22.9	18.5		18.5
Total comprehensive income							57.7
Dividends			(21.5)		(21.5)		(21.5)
Other equity transactions		(0.3)	(0.3)		(0.6)	0.4	(0.2)
At 31 December 2013	8.0	40.3	284.5	22.7	355.5	0.5	356.0
Net income for the period			21.9		21.9	0.1	22.0
Other comprehensive income			0.9	41.6	42.5		42.5
Total comprehensive income							64.5
Dividends			(39.4)		(39.4)		(39.4)
Other equity transactions		(0.1)	0.4		0.3	(0.2)	0.1
At 31 December 2014	8.0	40.2	268.4	64.3	380.8	0.4	381.2
Net income for the period			(37.5)		(37.5)	0.2	(37.3)
Other comprehensive income[1)]			7.3	27.4	34.7		34.7
Total comprehensive income							(2.6)
Dividends			(23.1)		(23.1)		(23.1)
Other equity transactions		(0.1)	(0.0)		(0.1)	(0.3)	(0.4)
At 31 December 2015	8.0	40.1	215.1	91.6	354.7	0.3	355.1

1) Currency translation adjustments of NOK 27.4 billion in 2015 are net of accumulated currency translation gains of NOK 3.3 billion reclassified to the Consolidated statement of income related to the sale of interests in the Shah Deniz project, the South Caucasus Pipeline and the Trans Adriatic Pipeline AG. See note 4 *Acquisitions and dispositions*.

Refer to note 17 *Shareholders' equity*.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	2015	2014	Full year 2013
Income before tax		4.3	109.4	138.4
Depreciation, amortisation and net impairment losses	11, 12	133.8	101.4	72.4
Exploration expenditures written off	12	17.1	13.7	3.1
(Gains) losses on foreign currency transactions and balances		(0.4)	(3.1)	4.8
(Gains) losses from dispositions	4	(17.3)	(12.4)	(17.6)
(Increase) decrease in other items related to operating activities		19.8	3.9	6.6
(Increase) decrease in net derivative financial instruments	25	9.2	(2.8)	11.7
Interest received		2.9	2.1	2.1
Interest paid		(3.6)	(3.4)	(2.5)
Cash flows provided by operating activities before taxes paid and working capital items		165.8	208.8	218.8
Taxes paid		(65.7)	(96.6)	(114.2)
(Increase) decrease in working capital		8.9	14.2	(3.3)
Cash flows provided by operating activities		109.0	126.5	101.3
Additions through business combinations	4	(3.5)	0.0	0.0
Capital expenditures and investments		(124.7)	(122.6)	(114.9)
(Increase) decrease in financial investments		(19.8)	(12.7)	(23.2)
(Increase) decrease in other non-current items		(0.3)	0.8	0.6
Proceeds from sale of assets and businesses	4	33.2	22.6	27.1
Cash flows used in investing activities		(115.1)	(112.0)	(110.4)
New finance debt	18	32.2	20.6	62.8
Repayment of finance debt		(11.4)	(9.7)	(7.3)
Dividend paid	17	(22.9)	(33.7)	(21.5)
Net current finance debt and other		(5.5)	(0.3)	(7.3)
Cash flows provided by (used in) financing activities		(7.5)	(23.1)	26.6
Net increase (decrease) in cash and cash equivalents		(13.6)	(8.6)	17.5
Effect of exchange rate changes on cash and cash equivalents		7.1	5.7	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	16	82.4	85.3	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	16	75.9	82.4	85.3

Cash and cash equivalents included a bank overdraft of NOK 0.1 billion at 31 December 2015, a bank overdraft of NOK 0.7 billion at 31 December 2014 and a bank overdraft that was rounded to zero at 31 December 2013.

Interest paid in cash flows provided by operating activities is excluding capitalised interest of NOK 3.2 billion at 31 December 2015, NOK 1.6 billion at 31 December 2014 and NOK 1.1 billion at 31 December 2013. Capitalised interest is included in *Capital expenditures and investments* in cash flows used in investing activities.

8.1 Notes to the Consolidated financial statements

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway. The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil ASA is listed on the Oslo Børs (Norway) and the New York Stock Exchange (USA).

The Statoil group's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products and other forms of energy.

All the Statoil group's oil and gas activities and net assets on the Norwegian continental shelf are owned by Statoil Petroleum AS, a 100% owned operating subsidiary. Statoil Petroleum AS is co-obligor or guarantor of certain debt obligations of Statoil ASA.

The Consolidated financial statements of Statoil for the full year 2015 were authorised for issue in accordance with a resolution of the board of directors on 9 March 2016.

2 Significant accounting policies

Statement of compliance
The Consolidated financial statements of Statoil ASA and its subsidiaries (Statoil) have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU) and also comply with IFRSs as issued by the International Accounting Standards Board (IASB), effective at 31 December 2015.

Basis of preparation
The financial statements are prepared on the historical cost basis with some exceptions, as detailed in the accounting policies set out below. These policies have been applied consistently to all periods presented in these Consolidated financial statements. Certain amounts in the comparable years have been restated to conform to current year presentation. The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

Operating related expenses in the Consolidated statement of income are presented as a combination of function and nature in conformity with industry practice. *Purchases [net of inventory variation]* and *Depreciation, amortisation and net impairment losses* are presented in separate lines by their nature, while *Operating expenses* and *Selling, general and administrative expenses* as well as *Exploration expenses* are presented on a functional basis. Significant expenses such as salaries, pensions, etc. are presented by their nature in the notes to the Consolidated financial statements.

Standards and amendments to standards, issued but not yet adopted
At the date of these Consolidated financial statements, the following standards and amendments to standards applicable to Statoil have been issued, but were not yet effective:

- IFRS 15 *Revenue from Contracts with Customers*, issued in May 2014 and, following an amendment to the standard issued in September 2015, effective from 1 January 2018, covers the recognition of such revenue in the financial statements and related disclosure and will replace IAS 18 *Revenue*. The standard requires identification of the performance obligations for the transfer of goods and services in each contract with customers. Revenue will be recognised upon satisfaction of the performance obligations in the amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods and services. The standard requires adoption either on a retrospective basis or on the basis of the cumulative effect on retained earnings. Statoil is still in the process of evaluating the potential impact of IFRS 15, and has not yet determined its adoption date or its implementation method for the standard

- The amendment to IFRS 11 *Accounting for Acquisitions of Interests in Joint Operations*, issued in May 2014 and effective from 1 January 2016, establishes requirements for the accounting for acquisitions of interests in joint operations in which the activity constitutes a business. The amendment is to be applied prospectively. Statoil has adopted the amendment on the effective date

- IFRS 9 *Financial Instruments*, issued in its final form in July 2014 and effective from 1 January 2018, will replace IAS *39 Financial Instruments: Recognition and Measurement*. IFRS 9 introduces a new model for classification and measurement of financial assets and financial liabilities, a reformed approach to hedge accounting, and a more forward-looking impairment model. The standard's transition provisions partly require retrospective adoption, and partly prospective adoption. Statoil is in the process of evaluating the potential impact of IFRS 9, and has not yet determined its adoption date for the standard

- The amendments to IFRS 10 *Consolidated Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*, issued in September 2014 and, following an amendment issued in December 2015, effective from a future date to be determined by the IASB, establish requirements for the accounting for sales or contributions of assets between an investor and its associate or joint venture. Whether or not the assets are housed in a subsidiary, a full gain or loss will be recognised in the statement of income when the transaction involves assets that constitute a business, whereas a partial gain or loss will be recognised when the transaction involves assets that do not constitute a business. The amendments are to be applied prospectively. Statoil has not determined an adoption date for the amendments

- IFRS 16 *Leases*, issued in January 2016 and effective from 1 January 2019, covers the recognition of leases and related disclosure in the financial statements, and will replace IAS 17 *Leases*. In the financial statement of lessees, the new standard requires recognition of all contracts that qualify under its definition of a lease as right-of-use assets and lease liabilities in the balance sheet, while lease payments are to be reflected as interest expense and reduction of lease liabilities. The right-of-use assets are to be depreciated in accordance with IAS 16 *Property, Plant and Equipment* over the shorter of each contract's term and the assets' useful life. The standard consequently implies a significant change in lessees' accounting for leases currently defined as operating leases under IAS 17, both as regards impact on the balance sheet and the statement of income. IFRS 16 defines a lease as a contract that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. While this definition is not dissimilar to that of IAS 17, it would have required further evaluation of each contract to determine whether all leases included in Note 22 *Leases* of these financial statements, or contracts currently not defined as leases, would qualify as leases under the new standard. The standard introduces new requirements both as regards establishing the term of a lease and the related discounted cash flows that determine the amount of a lease liability to be recognised. The standard requires adoption either on a full retrospective basis, or retrospectively with the cumulative effect of initially recognising the standard as an adjustment to retained earnings at the date of initial application, and if so with a number of practical expedients in transitioning existing leases at the time of initial application. Statoil is in the early phase of evaluating the impact of IFRS 16, and has not yet determined its adoption date, its implementation method, or the expected impact of the standard on the Consolidated financial statements

- The disclosure initiative amendments to *IAS 7 Statement of Cash Flows,* issued in January 2016 and effective from 1 January 2017, establishes certain additional requirements as to disclosure of changes in financing liabilities. Statoil will implement the amendments on the effective date

Other standards and amendments to standards, issued but not yet effective, are either not expected to impact Statoil's Consolidated financial statements materially, or are not expected to be relevant to Statoil's Consolidated financial statements upon adoption.

Basis of consolidation

The Consolidated financial statements include the accounts of Statoil ASA and its subsidiaries and include Statoil's interest in jointly controlled and equity accounted investments.

Subsidiaries

Entities are determined to be controlled by Statoil, and consolidated in Statoil's financial statements, when Statoil has power over the entity, ability to use that power to affect the entity's returns, and exposure to, or rights to, variable returns from its involvement with the entity.

All intercompany balances and transactions, including unrealised profits and losses arising from Statoil's internal transactions, have been eliminated in full. Non-controlling interests are presented separately within equity in the balance sheet.

Joint operations and similar arrangements, joint ventures and associates

A joint arrangement is present where Statoil holds a long-term interest which is jointly controlled by Statoil and one or more other venturers under a contractual arrangement in which decisions about the relevant activities require the unanimous consent of the parties sharing control. Such joint arrangements are classified as either joint operations or joint ventures.

The parties to a joint operation have rights to the assets and obligations for the liabilities, relating to their respective share of the joint arrangement. In determining whether the terms of contractual arrangements and other facts and circumstances lead to a classification as joint operations, Statoil in particular considers the nature of products and markets of the arrangement and whether the substance of their agreements is that the parties involved have rights to substantially all the arrangement's assets. Statoil accounts for the assets, liabilities, revenues and expenses relating to its interests in joint operations in accordance with the principles applicable to those particular assets, liabilities, revenues and expenses. Normally this leads to accounting for the joint operation in a manner similar to the previous proportionate consolidation method.

Those of Statoil's exploration and production licence activities that are within the scope of IFRS 11 *Joint Arrangements* have been classified as joint operations. A considerable number of Statoil's unincorporated joint exploration and production activities are conducted through arrangements that are not jointly controlled, either because unanimous consent is not required among all parties involved, or no single group of parties has joint control over the activity. Licence activities where control can be achieved through agreement between more than one combination of involved parties are considered to be outside the scope of IFRS 11, and these activities are accounted for on a pro-rata basis using Statoil's ownership share. In determining whether each separate arrangement related to Statoil's unincorporated joint exploration and production licence activities is within or outside the scope of IFRS 11, Statoil considers the terms of relevant licence agreements, governmental concessions and other legal arrangements impacting how and by whom each arrangement is controlled. Subsequent changes in the ownership shares and number of licence participants, transactions involving licence shares, or changes in the terms of relevant agreements may lead to changes in Statoil's evaluation of control and impact a licence arrangement's classification in relation to IFRS 11 in Statoil's Consolidated financial statements. Currently there are no significant differences in Statoil's accounting for unincorporated licence arrangements whether in scope of IFRS 11 or not.

Joint ventures, in which Statoil has rights to the net assets, are accounted for using the equity method.

Investments in companies in which Statoil has neither control nor joint control, but has the ability to exercise significant influence over operating and financial policies, are classified as associates and are accounted for using the equity method.

Statoil as operator of joint operations and similar arrangements
Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated on an hours incurred basis to operating segments and Statoil operated joint operations under IFRS 11 and to similar arrangements (licences) outside the scope of IFRS 11. Costs allocated to the other partners' share of operated joint operations and similar arrangements reduce the costs in the Consolidated statement of income. Only Statoil's share of the statement of income and balance sheet items related to Statoil operated joint operations and similar arrangements are reflected in the Consolidated statement of income and the Consolidated balance sheet.

Reportable segments
Statoil identifies its operating segments on the basis of those components of Statoil that are regularly reviewed by the chief operating decision maker, Statoil's corporate executive committee (CEC). Statoil combines operating segments when these satisfy relevant aggregation criteria.

Statoil's accounting policies as described in this note also apply to the specific financial information included in reportable segments related disclosure in these Consolidated financial statements.

Foreign currency translation
In preparing the financial statements of the individual entities, transactions in foreign currencies (those other than functional currency) are translated at the foreign exchange rate at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the Consolidated statement of income as foreign exchange gains or losses within *Net financial items*. Foreign exchange differences arising from the translation of estimate-based provisions, however, generally are accounted for as part of the change in the underlying estimate and as such may be included within the relevant operating expense or income tax sections of the Consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured at historical cost in a foreign currency are translated using the exchange rate at the date of the transactions.

Presentation currency
For the purpose of the Consolidated financial statements, the statement of income, the balance sheet and the cash flows of each entity are translated from the functional currency into the presentation currency, Norwegian kroner (NOK). The assets and liabilities of entities whose functional currencies are other than NOK, including Statoil's parent company Statoil ASA whose functional currency is United States dollar (USD), are translated into NOK at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income (OCI). The cumulative amount of such translation differences relating to an entity and previously recognised in OCI, is reclassified to the Consolidated statement of income and reflected as a part of the gain or loss on disposal of that entity.

Business combinations
Determining whether an acquisition meets the definition of a business combination requires judgement to be applied on a case by case basis. Acquisitions are assessed under the relevant IFRS criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.

Business combinations, except for transactions between entities under common control, are accounted for using the acquisition method of accounting. The acquired identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of the acquisition. Acquisition costs incurred are expensed under *Selling, general and administrative expenses*.

Revenue recognition
Revenues associated with sale and transportation of crude oil, natural gas, petroleum products and other merchandise are recognised when risk passes to the customer, which is normally when title passes at the point of delivery of the goods, based on the contractual terms of the agreements.

Revenues from the production of oil and gas properties in which Statoil shares an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where Statoil has lifted and sold more than the ownership interest, an accrual is recognised for the cost of the overlift. Where Statoil has lifted and sold less than the ownership interest, costs are deferred for the underlift.

Revenue is presented net of customs, excise taxes and royalties paid in-kind on petroleum products. Revenue is presented gross of in-kind payments of amounts representing income tax.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as *Revenues* and *Purchases [net of inventory variation]* in the statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in *Revenues*.

Transactions with the Norwegian State
Statoil markets and sells the Norwegian State's share of oil and gas production from the Norwegian continental shelf (NCS). The Norwegian State's participation in petroleum activities is organised through the State's direct financial interest (SDFI). All purchases and sales of the SDFI's oil production are classified as *Purchases [net of inventory variation]* and *Revenues*, respectively. Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These sales and related expenditures refunded by the Norwegian State are presented net in the Consolidated financial statements.

Employee benefits
Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of Statoil.

Research and development
Statoil undertakes research and development both on a funded basis for licence holders and on an unfunded basis for projects at its own risk. Statoil's own share of the licence holders' funding and the total costs of the unfunded projects are considered for capitalisation under the applicable IFRS requirements. Subsequent to initial recognition, any capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax
Income tax in the Consolidated statement of income comprises current and deferred tax expense. *Income tax* is recognised in the Consolidated statement of income except when it relates to items recognised in OCI.

Current tax consists of the expected tax payable on the taxable income for the year and any adjustment to tax payable for previous years. Uncertain tax positions and potential tax exposures are analysed individually, and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recognised in the period in which they are earned or incurred, and are presented within *Net financial items* in the Consolidated statement of income. Uplift benefit on the NCS is recognised when the deduction is included in the current year tax return and impacts taxes payable.

Deferred tax assets and liabilities are recognised for the future tax consequences attributable to differences between the carrying amounts of existing assets and liabilities and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities, using tax rates enacted or substantively enacted at the balance sheet date. A deferred tax asset is recognised only to the extent that it is probable that future taxable income will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable income, convincing evidence is required, taking into account the existence of contracts, production of oil or gas in the near future based on volumes of proved reserves, observable prices in active markets, expected volatility of trading profits, expected currency rate movements and similar facts and circumstances.

Oil and gas exploration, evaluation and development expenditures
Statoil uses the successful efforts method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditures within *Intangible assets* until the well is complete and the results have been evaluated, or there is any other indicator of a potential impairment. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find. This evaluation is normally finalised within one year after well completion. If, following the evaluation, the exploratory well has not found potentially commercial quantities of hydrocarbons, the previously capitalised costs are evaluated for derecognition or tested for impairment. Geological and geophysical costs and other exploration and evaluation expenditures are expensed as incurred.

Capitalised exploration and evaluation expenditures, including expenditures to acquire mineral interests in oil and gas properties, related to offshore wells that find proved reserves are transferred from exploration expenditures and acquisition costs - oil and gas prospects (*Intangible assets*) to *Property, plant and equipment* at the time of sanctioning of the development project. For onshore wells where no sanction is required, the transfer of acquisition cost - oil and gas prospects (*Intangible assets*) to *Property, plant and equipment* occurs at the time when a well is ready for production.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partner's (farmor's) exploration and/or future development expenditures (carried interests), these expenditures are reflected in the Consolidated financial statements as and when the exploration and development work progresses. Statoil reflects exploration and evaluation asset dispositions (farm-out arrangements) on a historical cost basis with no gain or loss recognition.

A gain or loss related to a post-tax based disposition of assets on the NCS includes the release of tax liabilities previously computed and recognised related to the assets in question. The resulting gross gain or loss is recognised in full in *Other income* in the Consolidated statement of income.

Consideration from the sale of an undeveloped part of an onshore asset reduces the carrying amount of the asset. The part of the consideration that exceeds the carrying amount of the asset, if any, is reflected in the Consolidated statement of income under *Other income*.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.

Property, plant and equipment
Property, plant and equipment is reflected at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of an asset retirement obligation, if any, exploration costs transferred from intangible assets and, for qualifying assets, borrowing costs. Property, plant and equipment include costs relating to expenditures incurred under the terms of profit sharing agreements (PSAs) in certain countries, and which qualify for recognition as assets of Statoil. State-owned entities in the respective countries, however, normally hold the legal title to such PSA-based property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up, unless the fair value of neither the asset received nor the asset given up is measurable with sufficient reliability.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset is replaced and it is probable that future economic benefits associated with the item will flow to Statoil, the expenditure is capitalised. Inspection and overhaul costs, associated with regularly scheduled major maintenance programs planned and carried out at recurring intervals exceeding one year, are capitalised and amortised over the period to the next scheduled inspection and overhaul. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditures, development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of production wells, and field-dedicated transport systems for oil and gas are capitalised as producing oil and gas properties within *Property, plant and equipment.* Such capitalised costs, when designed for significantly larger volumes than the reserves from already developed and producing wells, are depreciated using the unit of production method based on proved reserves expected to be recovered from the area during the concession or contract period. Depreciation of production wells uses the unit of production method based on proved developed reserves, and capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. In the rare circumstances where the use of proved reserves fails to provide an appropriate measure of depreciation, a more appropriate reserve estimate is used. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production assets, Statoil has established separate depreciation categories which as a minimum distinguish between platforms, pipelines and wells.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis, and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in *Other income* or *Operating expenses*, respectively, in the period the item is derecognised.

Leases

Leases for which Statoil assumes substantially all the risks and rewards of ownership are reflected as finance leases. When an asset leased by a joint operation or similar arrangement to which Statoil is a party qualifies as a finance lease, Statoil reflects its proportionate share of the leased asset and related obligations. Finance leases are classified in the Consolidated balance sheet within *Property, plant and equipment* and *Finance debt*. All other leases are classified as operating leases, and the costs are charged to the relevant operating expense related caption on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to Statoil.

Statoil distinguishes between lease and capacity contracts. Lease contracts provide the right to use a specific asset for a period of time, while capacity contracts confer on Statoil the right to and the obligation to pay for certain volume capacity availability related to transport, terminal use, storage, etc. Such capacity contracts that do not involve specified assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by Statoil to qualify as leases for accounting purposes. Capacity payments are reflected as *Operating expenses* in the Consolidated statement of income in the period for which the capacity contractually is available to Statoil.

Intangible assets including goodwill

Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include acquisition cost for oil and gas prospects, expenditures on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets.

Intangible assets relating to expenditures on the exploration for and evaluation of oil and natural gas resources are not amortised. When the decision to develop a particular area is made, its intangible exploration and evaluation assets are reclassified to *Property, plant and equipment*.

Goodwill is initially measured at the excess of the aggregate of the consideration transferred and the amount recognised for any non-controlling interest over the fair value of the identifiable assets acquired and liabilities assumed in a business combination at the acquisition date. Goodwill acquired is allocated to each cash generating unit, or group of units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Financial assets

Financial assets are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the Measurement of fair values section below. The subsequent measurement of the financial assets depends on which category they have been classified into at inception.

At initial recognition, Statoil classifies its financial assets into the following three main categories: Financial investments at fair value through profit or loss, loans and receivables, and available-for-sale (AFS) financial assets. The first main category, financial investments at fair value through profit or loss, further consists of two sub-categories: Financial assets held for trading and financial assets that on initial recognition are designated as fair value through profit and loss. The latter approach may also be referred to as the fair value option.

Cash and cash equivalents include cash in hand, current balances with banks and similar institutions, and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to an insignificant risk of changes in fair value and have a maturity of three months or less from the acquisition date.

Trade receivables are carried at the original invoice amount less a provision for doubtful receivables which is made when there is objective evidence that Statoil will be unable to recover the balances in full.

A significant part of Statoil's investments in treasury bills, commercial papers, bonds and listed equity securities is managed together as an investment portfolio of Statoil's captive insurance company and is held in order to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Financial assets are presented as current if they contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial assets and financial liabilities are shown separately in the Consolidated balance sheet, unless Statoil has both a legal right and a demonstrable intention to net settle certain balances payable to and receivable from the same counterparty, in which case they are shown net in the balance sheet.

Inventories

Inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Impairment

Impairment of property, plant and equipment and intangible assets other than goodwill

Statoil assesses individual assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Assets are grouped into cash generating units (CGUs) which are the smallest identifiable groups of assets that generate cash inflows that are largely independent of the cash inflows from other groups of assets. Normally, separate CGUs are individual oil and gas fields or plants. Each unconventional asset play is considered a single CGU when no cash inflows from parts of the play can be reliably identified as being largely independent of the cash inflows from other parts of the play. In impairment evaluations, the carrying amounts of CGUs are determined on a basis consistent with that of the recoverable amount. In Statoil's line of business, judgement is involved in determining what constitutes a CGU. Development in production, infrastructure solutions, markets, product pricing, management actions and other factors may over time lead to changes in CGUs such as the division of one original CGU into several.

In assessing whether a write-down of the carrying amount of a potentially impaired asset is required, the asset's carrying amount is compared to the recoverable amount. The recoverable amount of an asset is the higher of its fair value less cost of disposal and its value in use. Fair value less cost of disposal is determined based on comparable recent arm's length market transactions, or based on Statoil's estimate of the price that would be received for the asset in an orderly transaction between market participants. Value in use is determined using a discounted cash flow model. The estimated future cash flows applied are based on reasonable and supportable assumptions and represent management's best estimates of the range of economic conditions that will exist over the remaining useful life of the assets, as set down in Statoil's most recently approved long-term forecasts. Statoil uses an approach of regular updates of assumptions and economic conditions in establishing the long-term forecasts which are reviewed by corporate management and updated at least annually. For assets and CGUs with an expected useful life or timeline for production of expected reserves extending beyond 5 years, the forecasts reflect expected production volumes for oil and natural gas, and the related cash flows include project or asset specific estimates reflecting the relevant period. Such estimates are established on the basis of Statoil's principles and assumptions consistently applied.

In performing a value-in-use-based impairment test, the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate which is based on Statoil's post-tax weighted average cost of capital (WACC). The use of post-tax discount rates in determining value in use does not result in a materially different determination of the need for, or the amount of, impairment that would be required if pre-tax discount rates had been used.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least once a year. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified or where the economic viability of that major capital expenditure depends on the successful completion of further exploration work, will remain capitalised during the evaluation phase for the exploratory finds. Thereafter it will be considered a trigger for impairment evaluation of the well if no development decision is planned for the near future and there are no concrete plans for future drilling in the licence.

An assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer be relevant or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

Impairment losses and reversals of impairment losses are presented in the Consolidated statement of income as *Exploration expenses* or *Depreciation, amortisation and net impairment losses*, on the basis of their nature as either exploration assets (intangible exploration assets) or development and producing assets (property, plant and equipment and other intangible assets), respectively.

Impairment of goodwill

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the CGU, or group of units, to which the goodwill relates. Where the recoverable amount of the CGU, or group of units, is less than the carrying amount, an impairment loss is recognised. Once recognised, impairments of goodwill are not reversed in future periods.

Financial liabilities

Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil are either financial liabilities at fair value through profit or loss or financial liabilities measured at amortised cost using the effective interest method. The latter applies to Statoil's non-current bank loans and bonds.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, or if they are held for the purpose of being traded. Financial liabilities are derecognised when the contractual obligations expire, are discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised either in interest income and other financial items or in interest and other finance expenses within *Net financial items*.

Derivative financial instruments

Statoil uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. Such derivative financial instruments are initially recognised at fair value on the date on which a derivative contract is entered into and are subsequently re-measured at fair value through profit and loss. The impact of commodity-based derivative financial instruments is recognised in the Consolidated statement of income under *Revenues*, as such derivative instruments are related to sales contracts or revenue-related risk management for all significant purposes. The impact of other financial instruments is reflected under *Net financial items*.

Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets or liabilities expected to be recovered, or with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception of derivative financial instruments held for the purpose of being traded.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, are accounted for as financial instruments. However, contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with Statoil's expected purchase, sale or usage requirements, also referred to as own-use, are not accounted for as financial instruments. This is applicable to a significant number of contracts for the purchase or sale of crude oil and natural gas, which are recognised upon delivery.

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives and are reflected at fair value with subsequent changes through profit and loss, when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. Where there is an active market for a commodity or other non-financial item referenced in a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based on the active market in question. A price formula with indexation to other markets or products will however result in the recognition of a separate derivative. Where there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to a number of Statoil's long-term natural gas sales agreements.

Pension liabilities

Statoil has pension plans for employees that either provide a defined pension benefit upon retirement or a pension dependent on defined contributions and related returns. A portion of the contributions are provided for as notional contributions, for which the liability increases with a promised notional return, set equal to the actual return of assets invested through the ordinary defined contribution plan. For defined benefit plans, the benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary levels.

Statoil's proportionate share of multi-employer defined benefit plans are recognised as liabilities in the balance sheet to the extent that sufficient information is available and a reliable estimate of the obligation can be made.

Statoil's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their services in the current and prior periods. That benefit is discounted to determine its present value, and the fair value of any plan assets is deducted. The discount rate is the yield at the balance sheet date, reflecting the maturity dates approximating the terms of Statoil's obligations. The discount rate for the main part of the pension obligations has been established on the basis of Norwegian mortgage covered bonds, which are considered high quality corporate bonds. The cost of pension benefit plans is expensed over the period that the employees render services and become eligible to receive benefits. The calculation is performed by an external actuary.

The net interest related to defined benefit plans is calculated by applying the discount rate to the opening present value of the benefit obligation and opening present value of the plan assets, adjusted for material changes during the year. The resulting net interest element is presented in the statement of income as part of net pension cost within *Net operating income*. The difference between estimated interest income and actual return is recognised in the Consolidated statement of comprehensive income.

Past service cost is recognised when a plan amendment (the introduction or withdrawal of, or changes to, a defined benefit plan) or curtailment (a significant reduction by the entity in the number of employees covered by a plan) occurs, or when recognising related restructuring costs or termination benefits. The obligation and related plan assets are re-measured using current actuarial assumptions, and the gain or loss is recognised in the statement of income.

Actuarial gains and losses are recognised in full in the Consolidated statement of comprehensive income in the period in which they occur, while actuarial gains and losses related to provision for termination benefits are recognised in the Consolidated statement of income in the period in which they occur. Due to the parent company Statoil ASA's functional currency being USD, the significant part of Statoil's pension obligations will be payable in a foreign currency (i.e. NOK). As a consequence, actuarial gains and losses related to the parent company's pension obligation include the impact of exchange rate fluctuations.

Contributions to defined contribution schemes are recognised in the statement of income in the period in which the contribution amounts are earned by the employees.

Notional contribution plans, reported in the parent company Statoil ASA, are recognised as pension liabilities with the actual value of the notional contributions and promised return at reporting date. Notional contributions and changes in fair value of notional assets are recognised in the statement of income as periodic pension cost.

Periodic pension cost is accumulated in cost pools and allocated to operating segments and Statoil operated joint operations (licences) on an hours incurred basis and recognised in the statement of income based on the function of the cost.

Onerous contracts
Statoil recognises as provisions the net obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable cost of meeting the obligations under the contract exceeds the economic benefits expected to be received in relation to the contract. A contract which forms an integral part of the operations of a CGU whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the CGU, is included in impairment considerations for the applicable CGU.

Asset retirement obligations (ARO)
Provisions for ARO costs are recognised when Statoil has an obligation (legal or constructive) to dismantle and remove a facility or an item of property, plant and equipment and to restore the site on which it is located, and when a reliable estimate of that liability can be made. The amount recognised is the present value of the estimated future expenditures determined in accordance with local conditions and requirements. Cost is estimated based on current regulations and technology, considering relevant risks and uncertainties. The discount rate used in the calculation of the ARO is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows, adjusted for a credit premium which reflects Statoil's own credit risk. Normally an obligation arises for a new facility, such as an oil and natural gas production or transportation facility, upon construction or installation. An obligation may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations, or be based on commitments associated with Statoil's ongoing use of pipeline transport systems where removal obligations rest with the volume shippers. The provisions are classified under *Provisions* in the Consolidated balance sheet. Some of the refining and process operations are deemed to have indefinite lives, and in consequence, no ARO has been recognised for their plants.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment and is subsequently depreciated as part of the costs of the facility or item of property, plant and equipment. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. When a decrease in the ARO provision related to a producing asset exceeds the carrying amount of the asset, the excess is recognised as a reduction of *Depreciation, amortisation and net impairment losses* in the Consolidated statement of income. When an asset has reached the end of its useful life, all subsequent changes to the ARO provision are recognised as they occur in *Operating expenses* in the Consolidated statement of income. Removal provisions associated with Statoil's role as shipper of volumes through third party transport systems are expensed as incurred.

Measurement of fair values
Quoted prices in active markets represent the best evidence of fair value and are used by Statoil in determining the fair values of assets and liabilities to the extent possible. Financial instruments quoted in active markets will typically include commercial papers, bonds and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets, financial liabilities and derivative instruments are determined by reference to mid-market prices, at the close of business on the balance sheet date.

Where there is no active market, fair value is determined using valuation techniques. These include using recent arm's-length market transactions, reference to other instruments that are substantially the same, discounted cash flow analysis, and pricing models and related internal assumptions. In the valuation techniques, Statoil also takes into consideration the counterparty and its own credit risk. This is either reflected in the discount rate used or through direct adjustments to the calculated cash flows. Consequently, where Statoil reflects elements of long-term physical delivery commodity contracts at fair value, such fair value estimates to the extent possible are based on quoted forward prices in the market and underlying indexes in the contracts, as well as assumptions of forward prices and margins where observable market prices are not available. Similarly, the fair values of interest and currency swaps are estimated based on relevant quotes from active markets, quotes of comparable instruments, and other appropriate valuation techniques.

Critical accounting judgements and key sources of estimation uncertainty
Critical judgements in applying accounting policies
The following are the critical judgements, apart from those involving estimations (see below), that Statoil has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
As described under Transactions with the Norwegian State above, Statoil markets and sells the Norwegian State's share of oil and gas production from the NCS. Statoil includes the costs of purchase and proceeds from the sale of the SDFI oil production in *Purchases [net of inventory variation]* and *Revenues,* respectively. In making the judgement, Statoil considered the detailed criteria for the recognition of revenue from the sale of goods and, in particular, concluded that the risk and reward of the ownership of the oil had been transferred from the SDFI to Statoil.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. These gas sales, and related expenditures refunded by the State, are shown net in Statoil's Consolidated financial statements. In making the judgement, Statoil considered the same criteria as for the oil production and concluded that the risk and reward of the ownership of the gas had not been transferred from the SDFI to Statoil.

Key sources of estimation uncertainty
The preparation of the Consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets, liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an on-going basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors which affect the overall results, such as liquids prices, natural gas prices, refining margins, foreign exchange rates and interest rates as well as financial instruments with fair values derived from changes in these factors. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by, for instance, maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these Consolidated financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves
Proved oil and gas reserves may materially impact the Consolidated financial statements, as changes in the proved reserves, for instance as a result of changes in prices, will impact the unit of production rates used for depreciation and amortisation. Proved oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and governed by criteria established by regulations of the U.S. Securities Exchange Commission (SEC), which require the use of a price based on a 12-month average for reserve estimation, and which are to be based on existing economic conditions and operating methods and with a high degree of confidence (at least 90% probability) that the quantities will be recovered. The Financial Accounting Standards Board (FASB) requirements for supplemental oil and gas disclosures align with the SEC regulations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of this evaluation do not differ materially from Statoil's estimates. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence within a reasonable time.

Expected oil and gas reserves
Expected oil and gas reserves may materially impact the Consolidated financial statements, as changes in the expected reserves, for instance as a result of changes in prices, will impact asset retirement obligations and impairment testing of upstream assets, which in turn may lead to changes in impairment charges affecting operating income. Expected oil and gas reserves are the estimated remaining, commercially recoverable quantities, based on Statoil's judgement of future economic conditions, from projects in operation or justified for development. Recoverable oil and gas quantities are always uncertain, and the expected value is the weighted average, or statistical mean, of the possible outcomes. Expected reserves are therefore typically larger than proved reserves as defined by the SEC rules. Expected oil and gas reserves have been estimated by internal qualified professionals on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgements involving geological and engineering assessments of in-place hydrocarbon volumes, the production, historical recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Exploration and leasehold acquisition costs
Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgements as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment
Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired, requiring the carrying amount to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well, it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future and there is no concrete plan for future drilling in the licence.

Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of often volatile economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Impairment testing frequently also requires judgement regarding probabilities and probability distributions as well as levels of sensitivity inherent in the establishment of recoverable amount estimates. Long-term assumptions for major economic factors are made at a group level, and there is a high degree of reasoned judgement involved in establishing these assumptions, in determining other relevant factors such as forward price curves, in estimating production outputs and in determining the ultimate terminal value of an asset.

Employee retirement plans
When estimating the present value of defined benefit pension obligations that represent a long-term liability in the Consolidated balance sheet, and indirectly, the period's net pension expense in the Consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made about the discount rate to be applied to future benefit payments and plan assets, the expected rate of pension increase and the annual rate of compensation increase, have a direct and potentially material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the Consolidated financial statements.

Asset retirement obligations
Statoil has significant obligations to decommission and remove offshore installations at the end of the production period. It is difficult to estimate the costs of these decommissioning and removal activities, which are based on current regulations and technology, and consider relevant risks and uncertainties. Most of the removal activities are many years into the future, and the removal technology and costs are constantly changing. The estimates include assumptions of the time required and the day rates for rigs, marine operations and heavy lift vessels that can vary considerably depending on the assumed removal complexity. As a result, the initial recognition of the liability and the capitalised cost associated with decommissioning and removal obligations, and the subsequent adjustment of these balance sheet items, involve the application of significant judgement.

Derivative financial instruments
When not directly observable in active markets, the fair value of derivative contracts must be computed internally based on internal assumptions as well as directly observable market information, including forward and yield curves for commodities, currencies and interest rates. Changes in internal assumptions, forward and yield curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in a corresponding impact on income or loss in the Consolidated statement of income.

Income tax
Every year Statoil incurs significant amounts of income taxes payable to various jurisdictions around the world and recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon management's ability to properly apply at times very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

3 Segments

With effect from the third quarter of 2015 Statoil implemented a new corporate structure. Statoil's operations are now managed through the following operating segments: Development and Production Norway (DPN), Development and Production USA (DPUSA), Development and Production International (DPI), Marketing, Midstream and Processing (MMP), New Energy Solutions (NES) and Other.

The development and production operating segments are responsible for the commercial development of the oil and gas portfolios within their respective geographical areas: DPN on the Norwegian continental shelf, DPUSA including offshore and onshore activities in the USA and Mexico, and DPI worldwide outside of DPN and DPUSA.

Exploration activities are managed by a separate business unit, which has the global responsibility across the group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective development and production operating segments.

The MMP segment is responsible for marketing and trading of oil and gas commodities (crude, condensate, gas liquids, products, natural gas and liquefied natural gas), electricity and emission rights, as well as transportation, processing and manufacturing of the above mentioned commodities, operations of refineries, terminals, processing and power plants.

The NES segment is responsible for wind parks, carbon capture and storage as well as other renewable energy and low-carbon energy solutions.

Statoil reports its business through reporting segments which correspond to the operating segments, except for the operating segments DPI and DPUSA which have been aggregated into one reporting segment, Development and Production International. This aggregation has its basis in similar economic characteristics, the nature of products, services and production processes, the type and class of customers, the methods of distribution and regulatory environment. The new operating segment NES is reported in the segment Other in 2015 due to its immateriality.

The Other reporting segment includes activities within New Energy Solutions, Global Strategy and Business Development, Technology, Projects and Drilling and Corporate Staffs and Services.

The eliminations section includes the elimination of inter-segment sales and related unrealised profits, mainly from the sale of crude oil and products. Inter-segment revenues are based upon estimated market prices.

Segment data for the years ended 31 December 2015, 2014 and 2013 is presented below. The measurement basis of segment profit is *Net operating income*. In the tables below, deferred tax assets, pension assets and non-current financial assets are not allocated to the segments. Also, the line additions to PP&E, intangibles and equity accounted investments is excluding movements due to changes in asset retirement obligations.

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2015						
Revenues third party and other income	(0.9)	15.3	465.5	3.1	-	483.1
Revenues inter-segment	140.4	53.9	1.5	0.0	(195.7)	(0.0)
Net income (loss) from equity accounted investments	0.0	(0.8)	0.4	0.0	-	(0.3)
Total revenues and other income	139.5	68.4	467.4	3.2	(195.7)	482.8
Purchases [net of inventory variation]	(0.0)	(0.1)	(406.5)	(0.0)	195.4	(211.2)
Operating and SG&A expenses	(25.8)	(27.3)	(37.6)	(2.8)	1.5	(91.9)
Depreciation, amortisation and net impairment losses	(51.4)	(81.6)	0.4	(1.1)	0.0	(133.8)
Exploration expenses	(4.6)	(26.3)	0.0	0.0	0.0	(31.0)
Net operating income	57.6	(66.9)	23.7	(0.8)	1.2	14.9
Additions to PP&E, intangibles and equity accounted investments	50.6	65.4	7.3	2.2	0.0	125.5
Balance sheet information						
Equity accounted investments	0.0	2.9	1.9	2.4	-	7.3
Non-current segment assets	244.1	330.1	49.2	6.1	-	629.5
Non-current assets, not allocated to segments						82.0
Total non-current assets						718.7

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2014						
Revenues third party and other income	9.0	18.6	595.0	0.4	-	622.9
Revenues inter-segment	173.2	67.3	1.8	0.0	(242.3)	(0.0)
Net income (loss) from equity accounted investments	0.1	(0.8)	0.5	(0.0)	-	(0.3)
Total revenues and other income	182.2	85.2	597.3	0.3	(242.3)	622.7
Purchases [net of inventory variation]	(0.0)	(0.0)	(544.2)	(0.0)	242.9	(301.3)
Operating and SG&A expenses	(25.2)	(22.9)	(33.2)	(0.9)	2.0	(80.2)
Depreciation, amortisation and net impairment losses	(40.0)	(56.8)	(3.6)	(1.0)	-	(101.4)
Exploration expenses	(5.4)	(25.0)	(0.0)	0.0	-	(30.3)
Net operating income	111.7	(19.5)	16.2	(1.5)	2.6	109.5
Additions to PP&E, intangibles and equity accounted investments	55.1	61.4	7.8	0.8	-	125.1
Balance sheet information						
Equity accounted investments	0.2	4.8	3.2	0.2	-	8.4
Non-current segment assets	262.0	333.8	46.3	5.1	-	647.3
Non-current assets, not allocated to segments						76.0
Total non-current assets						731.7

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Other	Eliminations	Total
Full year 2013						
Revenues third party and other income	9.4	16.5	607.5	1.0	-	634.4
Revenues inter-segment	192.7	65.4	1.0	0.1	(259.1)	0.0
Net income (loss) from equity accounted investments	0.1	(0.0)	0.1	(0.0)	-	0.1
Total revenues and other income	202.2	81.9	608.6	1.0	(259.1)	634.5
Purchases [net of inventory variation]	0.0	(0.1)	(565.2)	(0.0)	258.4	(306.9)
Operating and SG&A expenses	(27.4)	(21.0)	(33.7)	(0.8)	1.1	(81.9)
Depreciation, amortisation and net impairment losses	(32.2)	(31.9)	(7.0)	(1.3)	0.0	(72.4)
Exploration expenses	(5.5)	(12.5)	(0.0)	(0.0)	0.0	(18.0)
Net operating income	137.1	16.4	2.6	(1.1)	0.4	155.5
Additions to PP&E, intangibles and equity accounted investments	57.3	52.9	5.9	1.3	-	117.4
Balance sheet information						
Equity accounted investments	0.2	4.8	2.3	0.2	-	7.4
Non-current segment assets	247.6	286.5	39.3	5.6	-	578.9
Non-current assets, not allocated to segments						60.5
Total non-current assets						646.8

See note 4 *Acquisitions and dispositions* for information on transactions that affect the different segments.

See note 11 *Property, plant and equipment* for information on impairment losses that affected the different segments.

See note 12 *Intangible assets* for information on impairment losses that affected primarily the DPI segment.

See note 23 *Other commitments, contingent liabilities and contingent assets* for information on contingencies that have influenced the DPI and MMP segments.

Revenues by geographical areas

Statoil has business operations in more than 30 countries. When attributing revenues third party and other income to the country of the legal entity executing the sale, Norway constitutes 76% and the USA constitutes 13%.

Non-current assets by country

(in NOK billion)	2015	2014	At 31 December 2013
Norway	277.4	289.6	269.6
USA	180.9	182.9	159.2
Angola	47.1	51.3	45.9
Brazil	30.6	29.5	24.5
UK	25.4	19.7	13.6
Canada	20.0	17.6	19.9
Algeria	12.6	11.8	9.0
Azerbaijan	12.5	23.6	19.0
Other countries	30.3	29.5	25.6
Total non-current assets[1)]	636.7	655.6	586.3

1) Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in NOK billion)	2015	2014	2013
Crude oil	223.1	324.6	321.5
Natural gas	99.6	99.3	110.4
Refined products	86.5	104.8	118.9
Natural gas liquids	44.2	59.5	64.5
Other	12.0	18.6	1.3
Total revenues	465.3	606.8	616.6

4 Acquisitions and disposals

2015

Sale of interests in the Marcellus onshore play

In January 2015 Statoil closed an agreement with Southwestern Energy, entered into in the fourth quarter 2014, reducing Statoil's average working interest in the non-operated southern Marcellus onshore play from 29% to 23%. The transaction was recognised in the Development and Production International (DPI) segment with no impact on the Consolidated statement of income. Proceeds from the sale were NOK 2.8 billion.

Sale of interests in the Shah Deniz project and the South Caucasus Pipeline

In April 2015 Statoil closed an agreement with Petronas, entered into in October 2014, to sell its remaining 15.5% interest in the Shah Deniz project and the South Caucasus Pipeline. Statoil recognised a total gain of NOK 12.4 billion. The gain was presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain was recognised in the DPI and the Marketing, Midstream and Processing (MMP) segments, with NOK 12.3 billion and NOK 0.1 billion, respectively. The part of the transaction recognised in the DPI segment was tax exempt under the rules in Norway and Azerbaijan. Total proceeds from the sale were NOK 20.3 billion, of which NOK 0.7 billion was received in 2014 and NOK 19.6 billion in 2015.

Sale of head office building

In June 2015 Statoil closed a transaction with Colony Capital, Inc. for the sale of the company's head office building in Stavanger through the sale of shares in the company Forusbeen 50 AS. At the same time, Statoil entered into a 15 year operating lease agreement for the building. A gain of NOK 1.5 billion was recognised in the Other segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. Proceeds from the sale were NOK 2.3 billion.

Sale of office buildings

In December 2015 Statoil closed a transaction with TRD Campus AS for the sale of the company's office buildings in Trondheim and Stjørdal through the sale of shares in the companies Strandveien 4 AS and Arkitekt Ebbelsvei 10 AS. At the same time Statoil entered into 15 year operating lease agreements for the buildings. A gain of NOK 0.6 billion was recognised in the Other segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. Proceeds from the sale were NOK 1.7 billion.

Sale of interests in the Trans Adriatic Pipeline AG

In December 2015 Statoil closed an agreement with Italian gas structure company Snam SpA to sell its 20% interest in Trans Adriatic Pipeline AG. A gain of NOK 1.4 billion was recognised in the MMP segment. The gain was tax exempt and presented in the line item *Other income* in the Consolidated statement of income. Total proceeds from the sale were NOK 2.0 billion.

Sale of interests in the Gudrun field and acquisition of interests in Eagle Ford
In December 2015 Statoil closed an agreement with Repsol to sell a 15% interest in the Gudrun field on the Norwegian continental shelf (NCS). Statoil remains the operator and largest equity holder with a 36% interest. Statoil recognised a total gain of NOK 1.2 billion in the Development and Production Norway (DPN) segment. The gain was presented in the line item *Other income* in the Consolidated statement of income. The transaction was tax exempt under the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 1.9 billion.

Simultaneously Statoil closed an agreement to acquire an additional 13% interest in the Eagle Ford formation with the same party. Statoil's total interest in the Eagle Ford shale play after the acquisition is 63%, and Statoil also became the sole operator. The acquisition was accounted for as a business combination using the acquisition method. The acquisition and valuation date for the purchase price allocation was 30 December 2015. The fair value of net identifiable assets was NOK 3.5 billion. The acquisition was recognised in the DPI and MMP reporting segments with the fair value of net identifiable assets of NOK 2.4 billion and NOK 1.1 billion, respectively. The total purchase price of the business combination was NOK 3.5 billion. No goodwill was recognised.

2014
Sale of interests in the Shah Deniz project and the South Caucasus Pipeline
In March 2014 Statoil closed an agreement with BP and in May 2014 Statoil closed an agreement with SOCAR, both entered into in December 2013, to divest a 3.33% working interest and a 6.67% working interest, respectively, in the Shah Deniz project and the South Caucasus Pipeline. Statoil recognised a total gain of NOK 5.4 billion, presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPI segment and the MMP segment with NOK 5.2 billion and NOK 0.2 billion, respectively. The part of the transaction recognised in the DPI segment was tax exempt under the rules in Norway and Azerbaijan. Proceeds from the sale were NOK 8.2 billion.

Kai Kos Dehseh oil sands swap agreement
In May 2014 Statoil and its partner PTTEP closed an agreement to swap the two parties' respective interests in the Kai Kos Dehseh oil sands project in Alberta, Canada. Statoil paid a balancing cash consideration of NOK 2.5 billion and assumed a net liability of NOK 0.3 billion. Subsequent to the closing, Statoil continues as 100% owner of the Leismer and Corner projects, while PTTEP owns 100% of the Thornbury, Hangingstone and South Leismer areas. The transaction has been recognised in the DPI segment resulting in an increase in *Property, plant and equipment* of NOK 4.6 billion, including a transfer from *Intangible assets* of NOK 1.8 billion, and with no impact on the Consolidated statement of income.

Sale of interests in licences on the Norwegian continental shelf
In December 2014 Statoil closed an agreement with Wintershall to sell certain ownership interests in licences on the NCS. A gain of NOK 5.9 billion has been recognised in the DPN segment. The gain has been presented in the line item *Other income* in the Consolidated statement of income. The transaction was tax exempt under the rules in the Norwegian petroleum tax legislation, and the gain included a release of related deferred tax liabilities. Proceeds from the sale were NOK 8.7 billion (USD 1.25 billion).

2013
Sale of interests in exploration and production licences on the Norwegian continental shelf to Wintershall
In July 2013 a sales transaction with Wintershall of certain ownership interests in licences on the NCS was closed. Statoil recognised a gain of NOK 6.4 billion. The gain has been presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPN segment in revenues third party and other income. The transaction was tax exempt under the rules in the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 4.7 billion.

Sale of interests in exploration and production licences on the Norwegian continental shelf and the United Kingdom continental shelf to OMV
In October 2013 a sales transaction with OMV to sell certain ownership interests in licences on the NCS and United Kingdom continental shelf was closed. Statoil recognised a gain of NOK 10.1 billion. The gain has been presented in the line item *Other income* in the Consolidated statement of income. In the segment reporting, the gain has been presented in the DPN segment and in the DPI segment in revenues third party and other income with NOK 6.6 billion and NOK 3.5 billion, respectively. The part of the transaction covering assets on the NCS was tax exempt under the rules in the Norwegian petroleum tax legislation. Proceeds from the sale were NOK 15.9 billion.

5 Financial risk management

General information relevant to financial risks
Statoil's business activities naturally expose Statoil to financial risk. Statoil's approach to risk management includes assessing and managing risk in all activities using a holistic risk approach. Statoil utilises correlations between the most important market risks, such as oil and natural gas prices, refined oil product prices, currencies, and interest rates, to calculate the overall market risk and thereby take into account the natural hedges inherent in Statoil's portfolio. Adding the different market risks without considering these correlations would overestimate Statoil's total market risk. This approach allows Statoil to reduce the number of risk management transactions and thereby reduce transaction costs and avoid sub-optimisation.

An important element in risk management is the use of centralised trading mandates. All major strategic transactions are required to be coordinated through Statoil's corporate risk committee. Mandates delegated to the trading organisations within crude oil, refined products, natural gas and electricity are relatively small compared to the total market risk of Statoil.

The corporate risk committee, which is headed by the chief financial officer and includes representatives from the principal business segments, is responsible for defining, developing and reviewing Statoil's risk policies. The chief financial officer, assisted by the committee, is also responsible for overseeing and developing Statoil's Enterprise Risk Management and proposing appropriate measures to adjust risk at the corporate level. The committee meets at least six times per year and regularly reviews risk information relevant to Statoil.

Financial risks
Statoil's activities expose Statoil to the following financial risks:
- Market risk (including commodity price risk, currency risk and interest rate risk)
- Liquidity risk
- Credit risk

Market risk
Statoil operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is exposed to market risks including fluctuations in hydrocarbon prices, foreign currency rates, interest rates, and electricity prices that can affect the revenues and costs of operating, investing and financing. These risks are managed primarily on a short-term basis with a focus on achieving the highest risk-adjusted returns for Statoil within the given mandate. Long-term exposures are managed at the corporate level, while short-term exposures are managed according to trading strategies and mandates approved by Statoil's corporate risk committee.

In the marketing of commodities Statoil has established guidelines for entering into derivative contracts in order to manage commodity price, foreign currency rate, and interest rate risks. Statoil uses both financial and commodity-based derivatives to manage the risks in revenues, financial items and the present value of future cash flows.

For more information on sensitivity analysis of market risk see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Commodity price risk
Statoil's most important long term commodity risk (oil and natural gas) is related to future market prices as Statoil's risk policy is to be exposed to both upside and downside price movements. To manage short-term commodity risk, Statoil enters into commodity- based derivative contracts, including futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and refined oil products are traded mainly on the Inter Continental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and crude and refined products swap markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, NASDAQ OMX Oslo forwards and futures traded on the NYMEX and ICE.

The term of crude oil and refined oil products derivatives is usually less than one year, and the term for natural gas and electricity derivatives is usually three years or less. For more detailed information about Statoil's commodity based derivative financial instruments, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Currency risk
Statoil's operating results and cash flows are affected by foreign currency fluctuations and the most significant currency is Norwegian Krone (NOK) against United States Dollar (USD). Statoil manages its currency risk from operating activities with USD as the base currency. Foreign exchange risk is managed at corporate level in accordance with established policies and mandates.

Statoil's cash flows from operating activities deriving from oil and gas sales, operating expenses and capital expenditures are mainly in USD, but taxes and dividends to shareholders on the Oslo Stock Exchange are in NOK. Accordingly, Statoil's currency management is primarily linked to mitigate currency risk related to tax and dividend payments in NOK. This means that Statoil regularly purchases substantial NOK amounts on a forward basis using conventional derivative instruments.

Interest rate risk
Bonds are normally issued at fixed rates in a variety of local currencies (among others USD, Euro and Great Britain Pound). Bonds may be converted to floating USD bonds by using interest rate and currency swaps. Statoil manages its interest rates exposure on its bond debt based on risk and reward considerations from an enterprise risk management perspective. This means that the fix/floating mix on interest rate exposure may vary from time to time. For more detailed information about Statoil's long-term debt portfolio see note 18 *Finance debt*.

Liquidity risk
Liquidity risk is the risk that Statoil will not be able to meet obligations of financial liabilities when they become due. The purpose of liquidity management is to make certain that Statoil has sufficient funds available at all times to cover its financial obligations.

Statoil manages liquidity and funding at the corporate level, ensuring adequate liquidity to cover Statoil's operational requirements. Statoil has a high focus and attention on credit and liquidity risk. In order to secure necessary financial flexibility, which includes meeting the financial obligations, Statoil maintains a conservative liquidity management policy. To identify future long-term financing needs, Statoil carries out three-year cash forecasts at least monthly.

The main cash outflows are the quarterly dividend payments and Norwegian petroleum tax payments paid six times per year. If the monthly cash flow forecast shows that the liquid assets one month after tax and dividend payments will fall below the defined policy level, new long-term funding will be considered.

Short-term funding needs will normally be covered by the USD 4.0 billion US Commercial Papers Programme (CP) which is backed by a revolving credit facility of USD 5.0 billion, supported by 21 core banks, maturing in 2020. The facility supports secure access to funding, supported by the best available short-term rating. As at 31 December 2015 it has not been drawn.

Statoil raises debt in all major capital markets (USA, Europe and Asia) for long-term funding purposes. The policy is to have a smooth maturity profile with repayments not exceeding five percent of capital employed in any year for the nearest five years. Statoil's non-current financial liabilities have a weighted average maturity of approximately nine years.

For more information about Statoil's non-current financial liabilities, see note 18 *Finance debt*.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for Statoil's financial liabilities.

		At 31 December
(in NOK billion)	2015	2014
Due within 1 year	104.9	131.4
Due between 1 and 2 years	73.7	43.3
Due between 3 and 4 years	86.9	81.3
Due between 5 and 10 years	93.8	90.5
Due after 10 years	115.5	84.3
Total specified	474.7	430.8

Credit risk

Credit risk is the risk that Statoil's customers or counterparties will cause Statoil financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Key elements of the credit risk management approach include:
- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- A continuous monitoring and managing of credit exposures

Prior to entering into transactions with new counterparties, Statoil's credit policy requires all counterparties to be formally identified and approved. In addition, all sales, trading and financial counterparties are assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed regularly and continuously monitored. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information like past payment performance, the counterparties' size and business diversification. The internal credit ratings reflect Statoil's assessment of the counterparties' credit risk. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics. Credit mandates define acceptable credit risk thresholds and are endorsed by management.

Statoil uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools include bank and parental guarantees, prepayments and cash collateral.

Statoil has pre-defined limits for the absolute credit risk level allowed at any given time on Statoil's portfolio as well as maximum credit exposures for individual counterparties. Statoil monitors the portfolio on a regular basis and individual exposures against limits on a daily basis. The total credit exposure portfolio of Statoil is geographically diversified among a number of counterparties within the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of Statoil's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments split by Statoil's assessment of the counterparty's credit risk. There are no significant receivables that are past due or impaired. Only non-exchange traded instruments are included in derivative financial instruments.

(in NOK billion)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2015				
Investment grade, rated A or above	0.0	14.6	11.9	2.0
Other investment grade	3.3	27.5	11.9	2.4
Non-investment grade or not rated	2.4	9.3	0.0	0.3
Total financial asset	5.8	51.4	23.8	4.8
At 31 December 2014				
Investment grade, rated A or above	0.0	20.1	15.2	2.4
Other investment grade	0.0	36.5	11.8	2.7
Non-investment grade or not rated	2.7	17.2	2.9	0.2
Total financial asset	2.7	73.7	29.9	5.3

At 31 December 2015, NOK 10.2 billion of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2014 NOK 12.9 billion was held as collateral. The collateral cash is received as a security to mitigate credit exposure related to positive fair values on interest rate swaps, cross currency swaps and foreign exchange swaps. Cash is called as collateral in accordance with the master agreements with the different counterparties when the positive fair values for the different swap agreements are above an agreed threshold.

Under the terms of various master netting agreements for derivative financial instruments as of 31 December 2015, NOK 7.0 billion presented as liabilities do not meet the criteria for offsetting. At 31 December 2014, NOK 5.2 billion was not offset. The collateral received and the amounts not offset from derivative financial instrument liabilities, reduce the credit exposure in the derivative financial instruments presented in the table above as they will offset each other in a potential default situation for the counterparty.

6 Remuneration

(in NOK billion, except average number of employees)	2015	2014	Full year 2013
Salaries[1)]	22.5	23.3	23.5
Pension costs	6.8	3.4	4.6
Payroll tax	3.4	3.5	3.4
Other compensations and social costs	2.5	2.4	2.5
Total payroll costs	35.2	32.5	34.0
Average number of employees[2)]	22,300	23,300	23,600

1) Salaries include bonuses, severance packages and expatriate costs in addition to base pay.
2) Part time employees amount to 3%, 2% and 3% for the years 2015, 2014 and 2013 respectively.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil operated licences on an hours incurred basis.

For further information on pension costs, see note 19 *Pensions*.

Compensation to the board of directors (BoD) and the corporate executive committee (CEC)
Remuneration to members of the BoD and the CEC during the year was as follows:

(in NOK million)[1]	2015	2014	Full year 2013
Current employee benefits	92.2	73.2	74.5
Post-employment benefits	6.4	13.0	13.0
Other non-current benefits	0.1	0.0	0.1
Share based payment benefits	1.3	1.1	1.1
Total	100.2	87.3	88.7

1) All figures in the table are presented on accrual basis.

At 31 December 2015, 2014 and 2013 there are no loans to the members of the BoD or the CEC.

Share-based compensation
Statoil's share saving plan provides employees with the opportunity to purchase Statoil shares through monthly salary deductions and a contribution by Statoil. If the shares are kept for two full calendar years of continued employment, following the year of purchase, the employees will be allocated one bonus share for each one they have purchased.

Estimated compensation expense including the contribution by Statoil for purchased shares, amounts vested for bonus shares granted and related social security tax was NOK 0.5 billion, NOK 0.6 billion and NOK 0.6 billion related to the 2015, 2014 and 2013 programs, respectively. For the 2016 program (granted in 2015) the estimated compensation expense is NOK 0.5 billion. At 31 December 2015 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 1.2 billion.

7 Other expenses

Auditor's remuneration

(in NOK million, excluding VAT)	2015	2014	Full year 2013
Audit fee	49	45	38
Audit related fee	14	8	8
Tax fee	0	0	0
Other service fee	0	0	0
Total	63	53	46

Of total increase in audit and audit related fees, NOK 3.2 million is due to currency effects, equivalent to 5%.

In addition to the figures in the table above, the audit fees and audit related fees related to Statoil operated licences amount to NOK 7 million, NOK 6 million and NOK 6 million for 2015, 2014 and 2013, respectively.

Research and development expenditures
Research and development (R&D) expenditures were NOK 2.7 billion, NOK 3.0 billion and NOK 3.2 billion in 2015, 2014 and 2013, respectively. R&D expenditures are partly financed by partners of Statoil operated licences. Statoil's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8 Financial items

(in NOK billion)	2015	2014	Full year 2013
Foreign exchange gains (losses) derivative financial instruments	4.4	(1.5)	(4.1)
Other foreign exchange gains (losses)	(6.5)	(0.7)	(4.5)
Net foreign exchange gains (losses)	(2.1)	(2.2)	(8.6)
Dividends received	0.3	0.3	0.1
Gains (losses) financial investments	0.4	1.1	1.9
Interest income financial investments	0.6	0.7	0.6
Interest income non-current financial receivables	0.2	0.1	0.1
Interest income current financial assets and other financial items	1.7	1.8	0.9
Interest income and other financial items	3.2	4.0	3.6
Interest expense bonds and bank loans and net interest on related derivatives	(5.7)	(4.3)	(1.5)
Interest expense finance lease liabilities	(0.2)	(0.3)	(0.2)
Capitalised borrowing costs	3.2	1.6	1.1
Accretion expense asset retirement obligations	(3.9)	(3.7)	(3.2)
Gains (losses) derivative financial instruments	(3.8)	5.8	(7.4)
Interest expense current financial liabilities and other finance expense	(1.2)	(0.8)	(0.8)
Interest and other finance expenses	(11.7)	(1.8)	(12.0)
Net financial items	(10.6)	(0.0)	(17.0)

Statoil's main financial items relate to assets and liabilities categorised in the held for trading category and the amortised cost category. For more information about financial instruments by category see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

The line item interest expense bonds and bank loans and net interest on related derivatives primarily includes interest expenses of NOK 8.6 billion, NOK 6.8 billion and NOK 5.4 billion from the financial liabilities at amortised cost category. This was partly offset by net interest on related derivatives from the held for trading category, NOK 2.6 billion, NOK 2.5 billion and NOK 3.9 billion for 2015, 2014 and 2013, respectively.

The line item gains (losses) derivative financial instruments primarily includes fair value loss from the held for trading category of NOK 4.0 billion, a gain of NOK 5.7 billion and a loss of NOK 7.6 billion for 2015, 2014 and 2013, respectively.

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk. The line item foreign exchange gains (losses) includes a net foreign exchange loss of NOK 9.7 billion, a loss of NOK 13.4 billion and a loss of NOK 4.3 billion from the held for trading category for 2015, 2014 and 2013, respectively.

9 Income taxes

Significant components of income tax expense

(in NOK billion)	2015	2014	Full year 2013
Current income tax expense in respect of current year	52.0	89.6	111.6
Prior period adjustments	0.7	(1.9)	1.3
Current income tax expense	52.7	87.6	112.9
Origination and reversal of temporary differences	(12.3)	(0.6)	(13.4)
Change in tax regulations	0.7	0.1	0.1
Prior period adjustments	0.4	0.3	(0.4)
Deferred tax expense	(11.1)	(0.2)	(13.7)
Income tax expense	41.6	87.4	99.2

During the normal course of its business, Statoil files tax returns in many different tax regimes. There may be differing interpretation of applicable tax laws and regulations regarding some of the matters in the tax returns. It may in certain cases take several years to complete the discussions with the relevant tax authorities or to reach a resolution of the tax positions through litigations. Statoil has provided for probable income tax related assets and liabilities based on best estimates reflecting consistent interpretations of the applicable laws and regulations.

Reconciliation of nominal statutory tax rate to effective tax rate

(in NOK billion)	2015	2014	Full year 2013
Income before tax	4.3	109.4	138.4
Calculated income tax at statutory rate[1)]	(8.5)	31.2	42.4
Calculated Norwegian Petroleum tax[2)]	33.4	62.8	71.7
Tax effect uplift[2)]	(6.8)	(6.4)	(5.2)
Tax effect of permanent differences regarding divestments	(3.7)	(6.2)	(12.0)
Tax effect of permanent differences caused by functional currency different from tax currency	(5.8)	(5.1)	(0.4)
Tax effect of other permanent differences	(0.2)	2.2	(3.7)
Change in unrecognised deferred tax assets	28.2	8.7	3.9
Change in tax regulations[3)]	0.7	0.1	0.1
Prior period adjustments	1.1	(1.7)	0.9
Other items including currency effects	3.2	1.7	1.5
Income tax expense	41.6	87.4	99.2
Effective tax rate	969.3%	79.9%	71.7%

1) The weighted average of statutory tax rates was -198.9% in 2015, 28.5% in 2014 and 30.7% in 2013. The negative weighted average of statutory tax rates for 2015 (198.9%) and the decrease in weighted average tax rates from 2014 to 2015 is mainly caused by losses, impairments and provisions in entities with higher than average statutory tax rates. The decrease from 2013 to 2014 was due to changes in the geographic mix of income, and a decrease in the Norwegian statutory tax rate from 28% to 27%.

2) When computing the petroleum tax of 51% (53% from 2016) on income from the Norwegian continental shelf, an additional tax-free allowance, or uplift, is granted at a rate of 5.5% per year on the basis of the original capitalised cost of offshore production installations. For investments made prior to 5 May 2013, the rate is 7.5% per year. Transitional rules apply to investments from 5 May 2013 covered by among others Plans for development and operation (PDOs) or Plans for installation and operation (PIOs) submitted to the Ministry of Oil and Energy prior to 5 May 2013. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift may be carried forward indefinitely. At year end 2015 and 2014, unrecognised uplift credits amounted to NOK 20.6 billion and NOK 21.1 billion, respectively.

3) The increase from 2014 to 2015 is mainly related to change in deferred taxes caused by a reduction in Norwegian statutory tax rate from 27% to 25% effective from 2016.

Deferred tax assets and liabilities comprise

(in NOK billion)	Tax losses carried forward	Property, plant and equipment and Intangible assets	Asset removal obligation	Pensions	Derivatives	Other	Total
Deferred tax at 31 December 2015							
Deferred tax assets	41.8	1.6	61.5	5.1	0.1	7.0	117.1
Deferred tax liabilities	(0.0)	(147.4)	0.0	(0.0)	(8.2)	(9.1)	(164.6)
Net asset (liability) at 31 December 2015	41.8	(145.7)	61.5	5.1	(8.1)	(2.1)	(47.6)
Deferred tax at 31 December 2014							
Deferred tax assets	36.7	4.6	73.3	7.0	0.2	13.4	135.3
Deferred tax liabilities	(0.0)	(172.6)	0.0	0.0	(12.9)	(8.4)	(193.8)
Net asset (liability) at 31 December 2014	36.7	(167.9)	73.3	7.0	(12.7)	4.9	(58.6)

Changes in net deferred tax liability during the year were as follows:

(in NOK billion)	2015	2014	2013
Net deferred tax liability at 1 January	58.6	62.8	77.3
Charged (credited) to the Consolidated statement of income	(11.1)	(0.2)	(13.7)
Other comprehensive income	2.8	(0.9)	(1.5)
Translation differences and other	(2.7)	(3.0)	0.7
Net deferred tax liability at 31 December	47.6	58.6	62.8

Deferred tax assets and liabilities are offset to the extent that the deferred taxes relate to the same fiscal authority, and there is a legally enforceable right to offset current tax assets against current tax liabilities. After netting deferred tax assets and liabilities by fiscal entity, deferred taxes are presented on the balance sheet as follows:

		At 31 December
(in NOK billion)	2015	2014
Deferred tax assets	17.8	12.9
Deferred tax liabilities	65.4	71.5

Deferred tax assets are recognised based on the expectation that sufficient taxable income will be available through reversal of taxable temporary differences or future taxable income. At year end 2015 and 2014 the deferred tax assets of NOK 17.8 billion and NOK 12.9 billion, respectively, were primarily recognised in Norway, Angola and the UK.

Unrecognised deferred tax assets

				At 31 December
		2015		2014
(in NOK billion)	Basis	Tax	Basis	Tax
Deductible temporary differences	21.6	8.9	11.0	3.2
Tax losses carried forward	126.2	46.7	52.5	18.0
Total	147.8	55.6	63.5	21.2

The movement in tax value of unrecognised deferred tax assets in the table above compared to reported change in unrecognised deferred tax assets in the table Reconciliation of nominal statutory tax rate to effective tax rate is mainly caused by currency effects.

Approximately 11% of the unrecognised carry forward tax losses can be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2026. The unrecognised deductible temporary differences do not expire under the current tax legislation. Deferred tax assets have not been recognised in respect of these items because currently there is insufficient evidence to support that future taxable profits will be available to secure utilisation of the benefits.

Total unrecognised deferred tax assets relates to:

(in NOK billion)	2015	At 31 December 2014
US	39.3	12.3
Angola	5.7	0.0
Ireland	2.5	1.8
Canada	2.4	1.9
Netherlands	1.7	1.4
Other	4.0	3.8
Total	55.6	21.2

10 Earnings per share

The weighted average number of ordinary shares is the basis for computing the basic and diluted earnings per share as disclosed in the Consolidated statement of income. The dilutive effect relates to treasury shares.

(in millions)	2015	2014	At 31 December 2013
Weighted average number of ordinary shares	3,179.4	3,180.0	3,180.7
Weighted average number of ordinary shares, diluted	3,188.8	3,188.9	3,188.9
Earnings per share for income attributable to equity holders of the company:			
Basic (NOK)	-11.80	6.89	12.53
Diluted (NOK)	-11.80	6.87	12.50

11 Property, plant and equipment

(in NOK billion)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2014	26.1	1,037.5	64.6	10.1	164.7	1,303.0
Additions and transfers	0.4	79.3	5.0	0.6	10.1	95.5
Disposals at cost[2)]	(0.2)	(13.2)	(8.0)	(3.5)	(9.3)	(34.2)
Effect of changes in foreign exchange	4.2	70.3	4.1	1.0	13.2	92.8
Cost at 31 December 2015	30.5	1,174.0	65.7	8.2	178.7	1,457.1
Accumulated depreciation and impairment losses at 31 December 2014	(20.1)	(656.7)	(48.2)	(4.8)	(11.1)	(740.9)
Depreciation	(1.4)	(81.9)	(2.2)	(0.4)	0.0	(85.9)
Impairment losses and transfers	0.0	(27.5)	(0.5)	(0.0)	(20.8)	(48.7)
Reversal of impairment losses	0.0	0.8	4.0	0.1	0.2	5.0
Accumulated depreciation and impairment disposed assets[2)]	0.0	6.6	2.6	1.5	(0.0)	10.8
Effect of changes in foreign exchange	(3.4)	(40.9)	(3.1)	(0.5)	(3.2)	(51.1)
Accumulated depreciation and impairment losses at 31 December 2015	(24.9)	(799.5)	(47.4)	(4.1)	(34.9)	(910.8)
Carrying amount at 31 December 2015	5.6	374.4	18.3	4.0	143.8	546.2
Estimated useful lives (years)	3-20	[1)]	15 - 20	20 - 33		

(in NOK billion)	Machinery, equipment and transportation equipment, including vessels	Production plants and oil and gas assets	Refining and manufacturing plants	Buildings and land	Assets under development	Total
Cost at 31 December 2013	21.1	869.9	60.2	8.4	135.5	1,095.1
Additions and transfers	1.0	108.4	2.0	0.7	23.8	135.9
Disposals at cost	(0.1)	(8.5)	(1.4)	(0.0)	(8.9)	(18.9)
Effect of changes in foreign exchange	4.1	67.7	3.8	1.1	14.3	91.0
Cost at 31 December 2014	26.1	1,037.5	64.6	10.1	164.7	1,303.0
Accumulated depreciation and impairment losses at 31 December 2013	(15.5)	(540.1)	(44.9)	(3.8)	(3.3)	(607.7)
Depreciation	(1.2)	(71.0)	(1.8)	(0.3)	(0.0)	(74.4)
Impairment losses	(0.3)	(16.1)	(1.2)	(0.2)	(7.1)	(24.8)
Reversal of impairment losses	0.0	0.3	1.8	0.0	0.2	2.3
Accumulated depreciation and impairment disposed assets	0.1	5.7	(0.2)	0.0	(0.0)	5.7
Effect of changes in foreign exchange	(3.2)	(35.4)	(2.0)	(0.5)	(1.0)	(42.0)
Accumulated depreciation and impairment losses at 31 December 2014	(20.1)	(656.7)	(48.2)	(4.8)	(11.1)	(740.9)
Carrying amount at 31 December 2014	6.0	380.8	16.4	5.3	153.6	562.1
Estimated useful lives (years)	3-20	[1]	15 - 20	20 - 33		

1) Depreciation according to unit of production method, see note 2 *Significant accounting policies*.
2) Includes NOK 5.8 billion related to a change in the classification of Statoil's investment in the Sheringham Shoal Windfarm (Scira Offshore Energy Ltd) from joint operation (pro-rata line by line consolidation) to joint venture (equity method) following changes in the joint operating agreements.

The carrying amount of assets transferred to *Property, plant and equipment* from *Intangible assets* in 2015 and 2014 amounted to NOK 2.7 billion and NOK 9.5 billion, respectively.

Impairments
During 2015 and 2014, Statoil recognised total net impairment losses of NOK 63.3 billion and NOK 38.2 billion respectively on *Property, plant and equipment* and *Intangible assets*.

(in NOK billion)	Property, plant and equipment	Intangible assets[3]	Total
At 31 December 2015			
Producing and development assets[1]	43.8	9.8	53.5
Goodwill[1]	0.0	4.2	4.2
Acquisition costs related to oil and gas prospects[2]	0.0	5.6	5.6
Total net impairment losses recognised	43.8	19.6	63.3
At 31 December 2014			
Producing and development assets[1]	22.5	6.0	28.5
Goodwill[1]	0.0	4.2	4.2
Acquisition costs related to oil and gas prospects[2]	0.0	5.5	5.5
Total net impairment losses recognised	22.5	15.7	38.2

1) Producing and development assets and goodwill are subject to impairment assessment under IAS 36. The total net impairment losses recognised under IAS 36 in 2015 and 2014 amount to NOK 57.7 billion and NOK 32.7 billion, respectively, including impairment of acquisition costs - oil and gas prospects (intangible assets).
2) Acquisition costs related to exploration activities, subject to impairment assessment under the successful efforts method.
3) See note 12 *Intangible assets*.

In assessing the need for impairment of the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to its recoverable amount. The recoverable amount is the higher of fair value less cost of disposal (FVLCOD) and estimated value in use (VIU).

The base discount rate for VIU calculations is 6.5% real after tax. The discount rate is derived from Statoil's weighted average cost of capital. A derived pre-tax discount rate would generally be in the range of 8-12%, depending on asset specific characteristics, such as specific tax treatments, cash flow profiles and economic life. The rates are not changed from last year. For certain assets a pre-tax discount rate could be outside this range, mainly due to special tax elements (for example permanent differences) affecting the pre-tax equivalent. See note 2 *Significant accounting policies* for further information regarding impairment on property, plant and equipment.

(in NOK billion)	Impairment method	Carrying amount before impairment	Carrying amount after impairment	Net impairment loss
At 31 December 2015				
Development and Production Norway	VIU	14.5	11.0	3.5
Development and Production International	VIU	219.5	171.2	48.3
Marketing, Midstream and Processing	VIU	5.2	8.7	(3.5)
Development and Production Norway	FVLCOD	22.9	17.7	5.2
Development and Production International	FVLCOD	4.2	0.0	4.2
Marketing, Midstream and Processing	FVLCOD	0.0	0.0	0.0
Total		266.3	208.6	57.7
At 31 December 2014				
Development and Production Norway	VIU	5.2	2.9	2.3
Development and Production International	VIU	187.9	168.4	19.5
Marketing, Midstream and Processing	VIU	8.8	7.9	0.9
Development and Production Norway	FVLCOD	18.3	18.3	0.0
Development and Production International	FVLCOD	25.4	15.4	10.0
Marketing, Midstream and Processing	FVLCOD	0.0	0.0	0.0
Total		245.6	212.9	32.7

During 2015 net impairment losses of NOK 57.7 billion were recognised, on producing and development assets and goodwill, primarily due to declining commodity price forecasts (primarily oil). The recoverable amount of assets tested for impairment was mainly based on VIU estimates on the basis of internal forecasts on costs, production profiles and commodity prices. For short term commodity prices, observed forward oil and gas price curves for the first two to three years have been used. Long term commodity price forecasts are based on internal price forecasts. The FVLCOD have partly been established through comparisons with observed market transactions and bids, and partly through internally prepared net present value estimates using assumed market participant assumptions. During 2014 impairment losses of NOK 32.7 billion were recognised on producing and development assets and goodwill.

Development and Production Norway (DPN)
In the DPN segment net impairment losses of NOK 8.7 billion were recognised in 2015, which were mainly related to conventional offshore assets in the development phase. The net impairment losses were triggered by reduction in commodity price reductions and project delays. In 2014 impairment losses of NOK 2.3 billion were recognised.

Development and Production International (DPI)
In the DPI segment net impairment losses of NOK 52.5 billion were recognised in 2015 of which NOK 28.3 billion related to unconventional onshore assets in USA, including NOK 4.2 billion of goodwill allocated to these assets. NOK 24.1 billion related to other conventional assets which were not considered significant on an individual cash generating unit level. Impairment losses of NOK 42.7 billion were recognised as *Depreciation, amortisation and net impairment losses* and NOK 9.8 billion as *Exploration expenses*, based on the impaired asset's nature. In 2014 impairment losses of NOK 29.5 billion were recognised.

The net impairment losses related to the unconventional onshore assets in North America, were mainly a result from reduced long term commodity price assumptions partly offset by operational performance improvements and cost reductions. The net impairment losses related to other conventional assets were primarily related to reduced commodity price assumptions, but also included an impairment loss related to an asset under development in the Gulf of Mexico due to installation damages and a consequential start-up delay.

Marketing, Midstream and Processing (MMP)
The MMP segment recognised a net impairment reversal of NOK 3.5 in 2015 mainly related to a refinery. The reversal of impairment was triggered by increased refinery margins and operational improvements. In 2014 net impairment losses of NOK 0.9 billion were recognised.

Sensitivities

Throughout 2015 and subsequent to year end, commodity prices have continued to be volatile. Significant downward adjustments of Statoil's commodity price assumptions would result in impairment losses on certain producing and development assets in Statoil's portfolio. The table below presents an estimate of the carrying amount of producing and development assets, that would be subject to impairment assessment if a further decline in commodity price forecasts over the lifetime of the assets were 20%. The sensitivity has been established on the assumption that all other factors would remain unchanged.

Carrying amount of producing and development assets which would be subject to impairment assessment assuming an additional decline in commodity price forecasts of 20%:

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Midstream and Processing	Total
Carrying amount subject to impairment assessment in 2015 (after impairment)[1]	48	230	9	287
Sensitivity: commodity price decline by 20%[2]	52	253	N/A	305

1) Relates to assets subject to impairment assessment under IAS 36. As a result of these impairment assessments, Statoil recognised a net impairment loss of NOK 57.7 billion and 32.7 billion in 2015 and 2014 respectively, as described above.

2) The sensitivity which is reflected in this line, relates to the carrying amount of assets subject to impairment assessment under IAS 36. Exploration and evaluation assets accounted for under IFRS 6 are not included.

The information in the table above is for indicative purposes only. A significant and prolonged decline in commodity prices would affect other assumptions, e.g. cost level, currency etc. A general decline in commodity price assumptions of 20% would result in mitigating actions by Statoil by optimising the respective business plans in order to reduce the exposure to changes in the macro environment. Considering the substantial uncertainties related to other relevant assumptions that would be triggered by a significant and prolonged decline in commodity price forecasts, Statoil does not disclose the expected impairment amount.

12 Intangible assets

(in NOK billion)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2014	22.9	53.4	12.1	3.4	91.8
Additions	9.5	4.5	0.0	(0.2)	13.8
Disposals at cost	(0.5)	(2.3)	(0.1)	(0.2)	(3.0)
Transfers	(0.7)	(2.0)	0.0	(0.0)	(2.7)
Expensed exploration expenditures previously capitalised	(1.7)	(15.4)	0.0	0.0	(17.1)
Effect of changes in foreign exchange	3.1	7.7	1.7	0.5	13.0
Cost at 31 December 2015	32.6	45.9	13.8	3.6	95.8
Accumulated depreciation and impairment losses at 31 December 2014			(5.2)	(1.4)	(6.6)
Amortisation and impairments for the year			(4.2)	(0.0)	(4.2)
Effect of changes in foreign exchange			(1.5)	(0.2)	(1.8)
Accumulated depreciation and impairment losses at 31 December 2015			(10.9)	(1.6)	(12.5)
Carrying amount at 31 December 2015	32.6	45.9	2.8	2.0	83.3

(in NOK billion)	Exploration expenses	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2013	20.3	58.6	10.5	3.1	92.4
Additions	7.1	1.5	0.0	(0.0)	8.7
Disposals at cost	(0.9)	(0.7)	(0.0)	(0.3)	(1.8)
Transfers	(4.1)	(5.5)	0.0	0.0	(9.5)
Expensed exploration expenditures previously capitalised	(2.7)	(11.1)	0.0	0.0	(13.7)
Effect of changes in foreign exchange	3.1	10.5	1.7	0.6	15.7
Cost at 31 December 2014	22.9	53.4	12.1	3.4	91.8
Accumulated depreciation and impairment losses at 31 December 2013			0.0	(0.9)	(0.9)
Amortisation and impairments for the year			(4.2)	(0.3)	(4.5)
Effect of changes in foreign exchange			(1.0)	(0.2)	(1.2)
Accumulated depreciation and impairment losses at 31 December 2014			(5.2)	(1.4)	(6.6)
Carrying amount at 31 December 2014	22.9	53.4	6.9	2.0	85.2

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

During 2015, intangible assets were impacted by impairments of acquisition costs related to exploration activities of NOK 5.6 billion primarily as a result from dry wells and uncommercial discoveries in Angola and the Gulf of Mexico. Additionally, Statoil recognised impairments of NOK 9.8 billion primarily related to unconventional onshore assets in USA and goodwill related to US onshore assets of NOK 4.2 billion.

Impairment losses and reversals of impairment losses are presented as *Exploration expenses* and *Depreciation, amortisation and net impairment losses* on the basis of their nature as exploration assets (intangible assets) and other intangible assets, respectively. The impairment losses and reversal of impairment losses are based on recoverable amount estimates triggered by changes in reserve estimates, cost estimates and market conditions. See note 11 *Property, plant and equipment* for more information on the basis for impairment assessments.

The table below shows the aging of capitalised exploration expenditures.

(in NOK billion)	2015	2014
Less than one year	12.8	9.2
Between one and five years	16.9	11.4
More than five years	2.9	2.3
Total	32.6	22.9

The table below shows the components of the exploration expenses.

(in NOK billion)	2015	2014	Full year 2013
Exploration expenditures	23.1	23.9	21.8
Expensed exploration expenditures previously capitalised	17.1	13.7	3.1
Capitalised exploration	(9.2)	(7.3)	(6.9)
Exploration expenses	31.0	30.3	18.0

13 Financial investments and non-current prepayments

Non-current financial investments

(in NOK billion)	2015	At 31 December 2014
Bonds	12.4	11.6
Listed equity securities	6.3	6.6
Non-listed equity securities	1.8	1.4
Financial investments	20.6	19.6

Bonds and listed equity securities relate to investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option.

Non-current prepayments and financial receivables

(in NOK billion)	2015	At 31 December 2014
Financial receivables interest bearing	6.7	3.7
Prepayments and other non-interest bearing receivables	1.8	2.0
Prepayments and financial receivables	8.5	5.7

Financial receivables interest bearing primarily relate to project financing of equity accounted company and loans to employees.

Current financial investments

(in NOK billion)	2015	At 31 December 2014
Time deposits	19.1	9.8
Interest bearing securities	67.4	49.4
Financial investments	86.5	59.2

At 31 December 2015 current *Financial investments* include NOK 6.0 billion investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option. The corresponding balance at 31 December 2014 was NOK 6.0 billion.

For information about financial instruments by category, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk.*

14 Inventories

(in NOK billion)	2015	At 31 December 2014
Crude oil	10.7	10.1
Petroleum products	5.1	6.0
Other	6.3	7.7
Inventories	22.0	23.7

Other inventory consists of natural gas, spare parts and operational materials, including drilling and well equipment.

The write-down of inventories from cost to net realisable value amounted to an expense of NOK 3.9 billion and NOK 4.0 billion in 2015 and 2014, respectively.

15 Trade and other receivables

(in NOK billion)	2015	At 31 December 2014
Trade receivables	39.3	57.8
Current financial receivables	6.5	6.9
Joint venture receivables	5.1	8.5
Equity accounted investments and other related party receivables	0.5	0.5
Total financial trade and other receivables	51.4	73.7
Non-financial trade and other receivables	7.4	9.6
Trade and other receivables	58.8	83.3

For more information about the credit quality of Statoil's counterparties, see note 5 *Financial risk management*. For currency sensitivities, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

16 Cash and cash equivalents

(in NOK billion)	2015	At 31 December 2014
Cash at bank available	9.2	13.5
Time deposits	13.2	32.5
Money market funds	4.0	3.6
Interest bearing securities	44.8	30.6
Restricted cash, including margin deposits	4.8	2.9
Cash and cash equivalents	76.0	83.1

Restricted cash at 31 December 2015 and 2014 includes collateral deposits related to trading activities of NOK 3.6 billion and NOK 2.0 billion, respectively. Collateral deposits are related to certain requirements set out by exchanges where Statoil is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

17 Shareholders' equity

At 31 December 2015 and 2014, Statoil's share capital of NOK 7,971,617,757.50 comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

Statoil ASA has only one class of shares and all shares have voting rights. The holders of shares are entitled to receive dividends as and when declared and are entitled to one vote per share at general meetings of the company.

Dividends declared and paid per share were NOK 1.80 for each of the first two quarters of 2015. From and including the third quarter of 2015, dividend is declared in USD. Interim dividends of USD 0.2201 per share for the third quarter of 2015 were declared in the fourth quarter of 2015 and have been recognised as a liability in the Consolidated financial statements. This amount will be paid in the first quarter of 2016.

The board of directors will propose to the annual general meeting to maintain a dividend of USD 0.2201 per share for the fourth quarter 2015 and the introduction of a two-year scrip dividend programme starting from the fourth quarter 2015. The scrip programme will give shareholders the option to receive quarterly dividends in cash or in newly issued shares in Statoil, at a 5% discount for the fourth quarter 2015.

In 2014 dividends of NOK 7.20 were paid and NOK 7.00 for 2013.

During 2015 a total of 4,057,902 treasury shares were purchased for NOK 0.6 billion and 3,203,968 treasury shares were allocated to employees participating in the share saving plan. In 2014 a total of 3,381,488 treasury shares were purchased for NOK 0.6 billion and 2,960,972 treasury shares were allocated to employees participating in the share saving plan. At 31 December 2015 Statoil had 11,009,183 treasury shares and at 31 December 2014 10,155,249 treasury shares, all of which are related to Statoil's share saving plan. For further information, see note 6 *Remuneration*.

18 Finance debt

Capital management

The main objectives of Statoil's capital management policy are to maintain a strong financial position and to ensure sufficient financial flexibility. One of the key ratios in the assessment of Statoil's financial robustness is net interest-bearing debt adjusted (ND) to capital employed adjusted (CE).

(in NOK billion)	At 31 December 2015	2014
Net interest-bearing debt adjusted (ND)	129.9	95.6
Capital employed adjusted (CE)	485.0	476.7
Net debt to capital employed adjusted (ND/CE)	26.8%	20.0%

ND is defined as Statoil's interest bearing financial liabilities less cash and cash equivalents and current financial investments, adjusted for collateral deposits and balances held by Statoil's captive insurance company (an increase of NOK 9.6 billion and NOK 8.0 billion for 2015 and 2014, respectively), balances related to the SDFI (a decrease of NOK 1.9 billion and NOK 1.6 billion for 2015 and 2014, respectively) and project financing exposure that does not correlate to the underlying exposure (unchanged and decrease of NOK 0.1 billion for 2015 and 2014, respectively). CE is defined as Statoil's total equity (including non-controlling interests) and ND.

Non-current finance debt

Finance debt measured at amortised cost

	Weighted average interest rates in %[1]		Carrying amount in NOK billion at 31 December		Fair value in NOK billion at 31 December[2]	
	2015	2014	2015	2014	2015	2014
Unsecured bonds						
United States Dollar (USD)	3.51	3.50	182.9	154.4	190.5	165.0
Euro (EUR)	2.28	3.99	63.4	37.6	66.0	43.8
Great Britain Pound (GBP)	6.08	6.08	18.0	15.9	23.8	22.3
Norwegian kroner (NOK)	4.18	4.18	3.0	3.0	3.3	3.5
Total			267.3	210.9	283.7	234.7
Unsecured loans						
Japanese yen (JPY)	4.30	4.30	0.7	0.6	0.8	0.9
Secured bank loans						
United States Dollar (USD)	-	4.20	-	0.1	-	0.1
Norwegian kroner (NOK)	3.11	3.11	0.5	0.3	0.5	0.3
Finance lease liabilities			5.1	5.4	5.0	5.6
Total			6.3	6.5	6.3	6.9
Total finance debt			273.6	217.4	289.9	241.6
Less current portion			9.7	12.3	9.7	12.3
Non-current finance debt			264.0	205.1	280.2	229.3

1) Weighted average interest rates are calculated based on the contractual rates on the loans per currency at 31 December and do not include the effect of swap agreements.

2) The fair value of the non-current financial liabilities is determined using a discounted cash flow model and is classified at level 2 in the fair value hierarchy. Interest rates used in the model are derived from the LIBOR and EURIBOR forward curves and will vary based on the time to maturity for the non-current financial liabilities. The credit premium used is based on indicative pricing from external financial institutions.

Unsecured bonds amounting to NOK 182.9 billion are denominated in USD and unsecured bonds amounting to NOK 70.1 billion are swapped into USD. Two bonds denominated in EUR amounting to NOK 14.3 billion are not swapped. The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Substantially all unsecured bond and unsecured bank loan agreements contain provisions restricting future pledging of assets to secure borrowings without granting a similar secured status to the existing bondholders and lenders.

The secured bank loan in NOK has been secured by real estate and land with a total book value of NOK 0.6 billion.

In 2015 Statoil issued the following bonds:

Issuance date	Amount in EUR billion	Interest rate in %	Maturity date
17 February 2015	1.00	1.625	February 2035
17 February 2015	1.25	1.250	February 2027
17 February 2015	1.00	0.875	February 2023
17 February 2015	0.50	floating	August 2019

Out of Statoil's total outstanding unsecured bond portfolio, 48 bond agreements contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is NOK 264 billion at the 31 December 2015 closing exchange rate.

For more information about the revolving credit facility, maturity profile for undiscounted cash flows and interest rate risk management, see note 5 *Financial risk management*.

Non-current finance debt maturity profile

(in NOK billion)	2015	At 31 December 2014
Year 2 and 3	54.9	27.3
Year 4 and 5	43.0	44.2
After 5 years	166.1	133.5
Total repayment of non-current finance debt	264.0	205.1
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	3.39	3.78

More information regarding finance lease liabilities is provided in note 22 *Leases*.

Current finance debt

(in NOK billion)	2015	At 31 December 2014
Collateral liabilities	10.2	12.9
Non-current finance debt due within one year	9.7	12.3
Other including bank overdraft	0.6	1.3
Total current finance debt	20.5	26.5
Weighted average interest rate (%)	1.90	2.12

Collateral liabilities relate mainly to cash received as security for a portion of Statoil's credit exposure.

19 Pensions

The Norwegian companies in the group are subject to the requirements of the Mandatory Company Pensions Act, and the company's pension scheme follows the requirements of the Act.

Statoil ASA and a number of its subsidiaries have defined contribution plans. The period's contributions are recognised in the Consolidated statement of income as pension cost for the period.

In 2014 Statoil ASA made a decision to change the company's main pension plan in Norway from a defined benefit plan to a defined contribution plan. The actual transitioning to the defined contribution plan took place in 2015. At the same time paid-up policies for the rights vested in the defined benefit plan were issued. Employees with less than 15 years of future service before their regular retirement age retained the existing defined benefit plans. For onshore employees between 37 and 51 years of age and offshore employees between 35 and 49 years of age a compensation plan has been established. The defined contribution plan in Norway is managed by an insurance company (Storebrand).

The new pension plans in Statoil ASA includes unfunded elements. These notional contribution plans are regulated equal to the return on asset for the main contribution plan and are valued at fair value and recognised as pension liabilities. See note 2 *Significant accounting policies* for more information about the accounting treatment of the notional contribution plans reported in Statoil ASA.

In addition to the closed pension plans in Statoil ASA, some of its subsidiaries have defined benefit plans. The defined benefit plans in Norway are managed and financed through Statoil Pensjon (Statoil's pension fund - hereafter "Statoil Pension"). Statoil Pension is an independent pension fund that covers the employees in Statoil's Norwegian companies. The purpose of Statoil Pension is to provide retirement and disability pension to members and survivor's pension to spouses, registered partners, cohabitants and children. The pension fund's assets are kept separate from the company's and group companies' assets. Statoil Pension is supervised by the Financial Supervisory Authority of Norway ("Finanstilsynet") and is licensed to operate as a pension fund.

The Norwegian National Insurance Scheme ("Folketrygden") provides pension payments (social security) to all retired Norwegian citizens. Such payments are calculated by references to a base amount ("Grunnbeløpet" or "G") annually approved by the Norwegian Parliament. Statoil's plan benefits are generally based on a minimum of 30 years of service and 66% of the final salary level, including an assumed benefit from the Norwegian National Insurance Scheme.

Due to national agreements in Norway, Statoil is a member of both the previous agreement-based early retirement plan ("AFP") and the AFP scheme applicable from 1 January 2011. Statoil paid a premium for both AFP schemes until 31 December 2015. After that date, premiums are only due on the latest AFP scheme. The premium in the latest scheme is calculated on the basis of the employees' income between 1 and 7.1 G. The premium is payable for all employees until age 62. Pension from the latest AFP scheme will be paid from the AFP plan administrator to employees for their full lifetime. Statoil has determined that its obligations under this multi-employer defined benefit plan can be estimated with sufficient reliability for recognition purposes. Accordingly, the estimated proportionate share of the latest AFP plan has been recognised as a defined benefit obligation.

The present values of the defined benefit obligation, except for the notional contribution plan, and the related current service cost and past service cost are measured using the projected unit credit method. The assumptions for salary increases, increases in pension payments and social security base amount are based on agreed regulation in the plans, historical observations, future expectations of the assumptions and the relationship between these assumptions. At 31 December 2015 the discount rate for the defined benefit plans in Norway was established on the basis of seven years' mortgage covered bonds interest rate extrapolated on a yield curve which matches the duration of Statoil's payment portfolio for earned benefits.

Social security tax is calculated based on a pension plan's net funded status and is included in the defined benefit obligation.

Statoil has more than one defined benefit plan, but the disclosure is made in total since the plans are not subject to materially different risks. Pension plans outside Norway are not material and as such not disclosed separately.

Net pension cost

(in NOK billion)	2015	2014	2013
Current service cost	3.0	4.7	4.0
Interest cost	1.5	3.1	2.5
Interest (income) on plan asset	(1.2)	(2.6)	(2.1)
Losses (gains) from curtailment, settlement or plan amendment	2.0	(1.9)	0.0[1)]
Actuarial (gains) losses related to termination benefits	(0.0)	(0.2)	0.0
Notional contributions	0.3	0.0	0.0
Defined benefit plans	5.7	3.2	4.4
Defined contribution plans	1.1	0.2	0.2
Total net pension cost	6.8	3.4	4.6

1) In 2015 and 2014 Statoil ASA offered early retirement (termination benefits) to a defined group of employees above the age of 58 years. The expenses of NOK 1.4 billion and NOK 1.6 billion respectively were recognised in the Consolidated statement of income. In addition, a plan amendment effect related to the changed pension scheme in Norway resulted in a recognition in the Consolidated statement of income of a loss of NOK 0.6 billion in 2015 and a gain of NOK 3.5 billion in 2014. The plan amendment effect was recalculated in 2015 due to actual transitioning from a defined benefit to a defined contribution plan took place in 2015 and all information was not available when calculating the effect in 2014.

Pension cost includes associated social security tax and is partly charged to partners of Statoil operated licences.

(in NOK billion)	2015	2014
Defined benefit obligations (DBO)		
Defined benefit obligations at 1 January	65.0	79.4
Current service cost	3.0	4.7
Interest cost	1.5	3.1
Actuarial (gains) losses - Demographic assumptions	0.0	(0.1)
Actuarial (gains) losses - Financial assumptions	(6.0)	4.8
Actuarial (gains) losses - Experience	(3.1)	(2.1)
Benefits paid	(1.9)	(2.0)
Losses (gains) from curtailment, settlement or plan amendment[1)]	2.2	(2.9)
Paid-up policies	(1.2)	(20.4)
Foreign currency translation	0.3	0.3
Changes in notional contribution liability	0.3	0.0
Defined benefit obligations at 31 December	60.1	65.0
Fair value of plan assets		
Fair value of plan assets at 1 January	45.1	62.3
Interest income	1.2	2.6
Return on plan assets (excluding interest income)	0.6	0.9
Company contributions	0.3	0.1
Benefits paid	(0.6)	(0.7)
Paid-up policies and personal insurance	(1.7)	(20.4)
Foreign currency translation	0.3	0.3
Fair value of plan assets at 31 December	45.2	45.1
Net pension liability at 31 December	(14.9)	(19.9)
Represented by:		
Asset recognised as non-current pension assets (funded plan)	11.3	8.0
Liability recognised as non-current pension liabilities (unfunded plans)	(26.2)	(27.9)
DBO specified by funded and unfunded pension plans	60.1	65.0
Funded	33.9	37.2
Unfunded	26.2	27.9
Actual return on assets	1.8	3.5

1) A loss of NOK 0.1 billion in 2015 and a gain of NOK 0.9 billion in 2014, related to the plan amendment, has been recognised against *Property, plant and equipment*.

As part of the change of Statoil ASA's main pension plan in Norway the estimated assets related to paid-up policies and personal insurance (new disability pension and children pension from 2015) and liabilities related to paid-up policies have been excluded from the amounts in the table above.

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

(in NOK billion)	2015	2014	2013
Net actuarial (losses) gains recognised in OCI during the year	9.7	0.2	(5.5)
Actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation	0.4	(0.2)	(0.4)
Tax effects of actuarial (losses) gains recognised in OCI	(2.8)	0.9	1.2
Recognised directly in OCI during the year net of tax	7.3	0.9	(4.7)
Cumulative actuarial (losses) gains recognised directly in OCI net of tax	(7.2)	(14.5)	(15.4)

The net actuarial gain in 2015 is mainly related to an updated assessment of the discount rate and expected rate of pension increase to be used for pension obligations in Norway.

The line item net actuarial (losses) gains recognised in OCI during the year in 2014 includes actuarial loss charged to partners of Statoil operated licences.

The line item actuarial (losses) gains related to currency effects on net obligation and foreign exchange translation includes the translation of the net pension obligation in NOK to the functional currency USD for the parent company, Statoil ASA, and the translation of the net pension obligation from the functional currency USD to Statoil's presentation currency NOK.

Actuarial assumptions

	Assumptions used to determine benefit costs in %		Assumptions used to determine benefit obligations in %	
	2015	2014	2015	2014
Discount rate	2.50	4.00	2.75	2.50
Rate of compensation increase	2.25	3.50	2.25	2.25
Expected rate of pension increase	1.50	2.50	1.00	1.50
Expected increase of social security base amount (G-amount)	2.25	3.25	2.25	2.25
Weighted-average duration of the defined benefit obligation			17.1	19.1

The assumptions presented are for the Norwegian companies in Statoil which are members of Statoil's pension fund. The defined benefit plans of other subsidiaries are immaterial to the consolidated pension assets and liabilities.

Expected attrition at 31 December 2015 was 0.4% and 0.1% for employees between 50-59 years and 60-67 years, respectively. Expected attrition at 31 December 2014 was 2.1%, 2.2%, 1.3%, 0.5% and 0.2% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

For population in Norway, the mortality table K2013, issued by The Financial Supervisory Authority of Norway, is used as the best mortality estimate.

Disability tables for plans in Norway developed by the actuary were implemented in 2013 and represent the best estimate to use for plans in Norway.

Sensitivity analysis

The table below presents an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2015. Actual results may materially deviate from these estimates.

	Discount rate		Expected rate of compensation increase		Expected rate of pension increase		Mortality assumption	
(in NOK billion)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	+ 1 year	- 1 year
Changes in:								
Defined benefit obligation at 31 December 2015	(4.3)	5.0	1.1	(1.0)	3.5	(3.1)	2.0	(2.2)
Service cost 2016	(0.2)	0.2	0.1	(0.0)	0.1	(0.1)	0.1	(0.1)

The sensitivity of the financial results to each of the key assumptions has been estimated based on the assumption that all other factors would remain unchanged. The estimated effects on the financial result would differ from those that would actually appear in the Consolidated financial statements because the Consolidated financial statements would also reflect the relationship between these assumptions.

Pension assets

The plan assets related to the defined benefit plans were measured at fair value. Statoil Pension invests in both financial assets and real estate.

Real estate properties owned by Statoil Pension amounted to NOK 3.4 billion and NOK 3.2 billion of total pension assets at 31 December 2015 and 2014, respectively, and are rented to Statoil companies.

The table below presents the portfolio weighting as approved by the board of Statoil Pension for 2015. The portfolio weight during a year will depend on the risk capacity.

(in %)	Pension assets on investments classes 2015	2014	Target portfolio weight
Equity securities	38.3	40.1	31 - 43
Bonds	40.3	38.7	36 - 48
Money market instruments	14.9	13.4	0 - 29
Real estate	5.0	4.8	5 - 10
Other assets	1.5	3.0	
Total	100.0	100.0	

In 2015 100% of the equity securities, 38% of bonds and 100% of money market instruments had quoted market prices in an active market (level 1). In 2014 100% of the equity securities, 38% of bonds and 86% of money market instruments had quoted market prices in an active market. Statoil does not have any equity securities, bonds or money market instruments classified in level 3. Real Estate is classified as level 3. For definition of the various levels, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

No company contribution is expected to be paid to Statoil Pension in 2016.

20 Provisions

(in NOK billion)	Asset retirement obligations	Claims and litigations	Other provisions	Total
Non-current portion at 31 December 2014	107.4	3.5	6.3	117.2
Current portion at 31 December 2014 reported as trade and other payables	1.4	13.6	2.1	17.0
Provisions at 31 December 2014	108.8	17.1	8.4	134.2
New or increased provisions	4.2	6.1	4.4	14.8
Decrease in the estimates	(16.2)	(2.2)	(3.3)	(21.7)
Amounts charged against provisions	(2.2)	(4.6)	(0.9)	(7.7)
Effects of change in the discount rate	(6.8)	0.0	(0.1)	(7.0)
Reduction due to divestments	(1.0)	0.0	(0.1)	(1.1)
Accretion expenses	3.9	0.0	0.0	3.9
Reclassification and transfer	(0.6)	0.0	(0.3)	(0.8)
Currency translation	4.8	2.7	0.9	8.4
Provisions at 31 December 2015	95.0	19.1	9.0	123.0
Current portion at 31 December 2015 reported as trade and other payables	1.3	9.2	2.8	13.4
Long term interest bearing provisions at 31 December 2015 reported as finance debt	0.0	0.0	0.2	0.2
Non-current portion at 31 December 2015	93.7	9.8	6.0	109.4

Expected timing of cash outflows

(in NOK billion)	Asset retirement obligations	Other provisions, including claims and litigations	Total
2016 - 2020	12.2	24.7	36.9
2021 - 2025	16.9	0.8	17.7
2026 - 2030	16.1	0.2	16.3
2031 - 2035	25.5	0.7	26.3
Thereafter	24.2	1.6	25.8
At 31 December 2015	95.0	28.1	123.0

Statoil's estimated asset retirement obligations (ARO) have reduced mainly due to a reduction in cost estimates for plugging and abandonment. Changes in ARO are reflected within *Property, plant and equipment* and *Provisions* in the Consolidated balance sheet. The timing of cash outflows related to ARO primarily depends on when the production ceases at the various facilities.

The claims and litigations category mainly relates to expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these are uncertain and dependent on various factors that are outside management's control.

See also comments on provisions in note 23 *Other commitments, contingent liabilities and contingent assets.*

The other provisions category relates to expected payments on onerous contracts, cancellation fees and other.

For further information of methods applied and estimates required, see note 2 *Significant accounting policies*.

21 Trade and other payables

(in NOK billion)	At 31 December 2015	2014
Trade payables	18.1	21.8
Non-trade payables and accrued expenses	20.8	25.2
Joint venture payables	22.8	28.9
Equity accounted investments and other related party payables	5.5	6.6
Total financial trade and other payables	67.2	82.5
Current portion of provisions and other payables	15.0	18.1
Trade and other payables	82.2	100.7

Included in current portion of provisions and other payables are certain provisions that are further described in note 23 *Other commitments, contingent liabilities and contingent assets.* For information regarding currency sensitivities, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk*. For further information on payables to equity accounted investments and other related parties, see note 24 *Related parties*.

22 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

In 2015, net rental expenditures were NOK 27.7 billion (NOK 22.9 billion in 2014 and NOK 17.4 billion in 2013) consisting of minimum lease payments of NOK 32.6 billion (NOK 28.4 billion in 2014 and NOK 21.2 billion in 2013) reduced with sublease payments received of NOK 4.9 billion (NOK 5.5 billion in 2014 and NOK 3.8 billion in 2013). Net rental expenditures in 2015 include rig cancellation payments of NOK 1.6 billion. No material contingent rent payments have been expensed in 2015, 2014 or 2013.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2015:

	Operating leases					
(in NOK billion)	Rigs	Vessels	Other	Total	Sublease	Net total
2016	18.2	5.0	2.4	25.6	(2.6)	23.0
2017	11.1	3.8	1.8	16.7	(0.9)	15.8
2018	7.3	3.2	1.6	12.1	(0.7)	11.3
2019	6.1	2.5	1.3	9.9	(0.7)	9.2
2020	4.2	2.2	1.3	7.8	(0.7)	7.0
Thereafter	9.0	6.6	12.2	27.8	(1.4)	26.4
Total future minimum lease payments	55.9	23.3	20.6	99.8	(7.1)	92.7

Statoil had certain operating lease contracts for drilling rigs at 31 December 2015. The remaining significant contracts' terms range from one month to eight years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. Certain rigs have been subleased in whole or for part of the lease term mainly to Statoil operated licenses on the Norwegian continental shelf. These leases are shown gross as operating leases in the table above.

Statoil has a long-term time charter agreement with Teekay for offshore loading and transportation in the North Sea. The contract covers the lifetime of applicable producing fields and at year end 2015 includes three crude tankers. The contract's estimated nominal amount was approximately NOK 7.0 billion at year end 2015, and it is included in the category vessels in the table above.

The category other includes future minimum lease payments to related parties of NOK 4.3 billion regarding the lease of one office building located in Bergen and owned by Statoil`s pension fund ("Statoil Pension"). These operating lease commitments extend to the year 2034. NOK 3.2 billion of the total is payable after 2020.

Statoil had finance lease liabilities of NOK 4.9 billion at 31 December 2015. The nominal minimum lease payments related to these finance leases amount to NOK 6.5 billion. *Property, plant and equipment* includes NOK 6.8 billion for finance leases that have been capitalised at year end (NOK 5.7 billion in 2014), mainly presented in the category machinery, equipment and transportation equipment, including vessels in note 11 *Property, plant and equipment*.

23 Other commitments, contingent liabilities and contingent assets

Contractual commitments

Statoil had contractual commitments of NOK 62.3 billion at 31 December 2015. The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

As a condition for being awarded oil and gas exploration and production licences, participants may be committed to drill a certain number of wells. At the end of 2015, Statoil was committed to participate in 32 offshore wells, with an average ownership interest of approximately 33%. Statoil's share of estimated expenditures to drill these wells amounts to NOK 7.7 billion. Additional wells that Statoil may become committed to participating in depending on future discoveries in certain licences are not included in these numbers.

Other long-term commitments

Statoil has entered into various long-term agreements for pipeline transportation as well as terminal use, processing, storage and entry/exit capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose on Statoil the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with durations of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil to entities accounted for as associates and joint ventures are included gross in the table below. Obligations payable by Statoil to entities accounted for as joint operations (for example pipelines) are included net (i.e. gross commitment less Statoil's ownership share).

Nominal minimum other long-term commitments at 31 December 2015:

(in NOK billion)	
2016	13.5
2017	12.8
2018	11.8
2019	12.2
2020	10.9
Thereafter	77.9
Total	139.1

Of the reported other long-term commitments, NOK 17.5 billion relates to pipeline commitments where the construction of these pipelines is pending governmental approval.

Contingent liabilities and contingent assets

During the annual audits of Statoil's participation in Block 4, Block 15, Block 17 and Block 31 offshore Angola, the Angolan Ministry of Finance has assessed additional profit oil and taxes due on the basis of activities that currently include the years 2002 up to and including 2012. Statoil disputes the assessments and is pursuing these matters in accordance with relevant Angolan legal and administrative procedures. On the basis of the assessments and continued activity on the four blocks up to and including 2015, the exposure for Statoil at year end 2015 is estimated to NOK 11.6 billion (USD 1.3 billion), the most significant part of which relates to profit oil elements. Statoil has provided in the Consolidated financial statements for its best estimate related to the assessments, reflected in the Consolidated statement of income mainly as a revenue reduction, with additional amounts reflected as interest expenses and tax expenses, respectively.

Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field. In October 2015, Statoil received the Expert's final ruling which implies a reduction of 5.17 percentage points in Statoil's equity interest in the field. Statoil had previously initiated arbitration proceedings to set aside interim decisions made by the Expert, but this was declined by the arbitration tribunal in its November 2015 judgment. Statoil has initiated proceedings before the Federal High Court in Lagos to set aside the arbitration award and also intends to initiate a new arbitration to set aside the Expert's final ruling. As of 31 December 2015, Statoil has recognised a provision of NOK 9.5 billion (USD 1.1 billion), net of tax, which reflects a reduction of 5.17 percentage points in Statoil's equity interest in the Agbami field. The provision is reflected within *Provisions* in the Consolidated balance sheet.

Some long-term gas sales agreements contain price review clauses. Certain counterparties have requested arbitration in connection with price review claims. The related exposure for Statoil has been estimated to an amount equivalent to approximately NOK 3.6 billion for gas delivered prior to year end 2015. Statoil has provided for its best estimate related to these contractual gas price disputes in the Consolidated financial statements, with the impact to the Consolidated statement of income reflected as revenue adjustments.

There is a dispute between the Nigerian National Petroleum Corporation (NNPC) and the partners (Contractor) in Oil Mining Lease (OML) 128 of the unitised Agbami field concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC). The dispute relates to the allocation between NNPC and Contractor of cost oil, tax oil and profit oil volumes. NNPC has claimed that since the start of production from Agbami, Contractor has lifted excess volumes compared to the PSC terms, and consequently NNPC has increased its lifting of oil. The Contractor disputed NNPC's position and initiated arbitration in the matter in accordance with the terms of the PSC. In 2015 the Arbitral Tribunal ruled in favour of Contractor's interpretation of the PSC on the main points. The Contractor is currently proceeding to enforce the favourable decision by the means available in the Nigerian legal system, while NNPC on its hand has initiated litigation concerning certain objections to the arbitration award. The Nigerian Federal Inland Revenue Service is also contesting the legality of the arbitration process as far as resolving tax related disputes goes, and is actively pursuing this view through the channels of the Nigerian legal system. Statoil's stake in the dispute at year end 2015 is mainly related to oil volumes previously lifted by NNPC contrary to the PSC terms. NNPC has so far kept on its overlifting contrary to the award. Following the arbitration award, Statoil's previous provision related to NNPC's claim has been reversed with the effect mainly reflected as revenue in the Consolidated statement of income.

In 2014, following a regular review process of Statoil's 2012 Consolidated financial statements, the Financial Supervisory Authority of Norway (the FSA) ordered Statoil to: *"Change its future accounting practices for redetermination of CGUs containing onerous contracts. Correct the described error by establishing a separate onerous contract provision for the Cove Point capacity contract in a financial period prior to Q1 2013. The correction shall be presented in the next periodic financial report. Information about the circumstances shall be given in notes to the accounts."* Statoil appealed the order and has been granted a stay in carrying out the FSA's order pending the final outcome of the appeal. The appeal is currently being assessed by the Norwegian Ministry of Finance and not yet concluded. If the outcome of the appeal would require implementing the FSA's order, a provision would be recognised against *Net operating income* in an earlier reporting period than 2013. As the contracts were fully provided for in 2013, there would be no impact on equity at 31 December 2013 or thereafter. The actual amount to be provided in an earlier period would depend on the period in which the provision would be recorded. The FSA order does not specify which period prior to the first quarter 2013 would be relevant for the provision to be recognised. Statoil's reading is that 2011 would be most relevant. There would be no impact on the 2015 and 2014 financial statements, however, the comparative amounts included therein for 2013 *Net operating income* and *Net income* would be NOK 5.6 billion and NOK 5.0 billion higher, respectively.

During the normal course of its business, Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset, in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its Consolidated financial statements for probable liabilities related to litigation and claims based on its best estimate. Statoil does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

Statoil is actively pursuing the above disputes through the contractual and legal means available in each case, but the timing of the ultimate resolutions and related cash flows, if any, cannot at present be determined with sufficient reliability.

Provisions related to claims are reflected within note 20 *Provisions*.

24 Related parties

Transactions with the Norwegian State

The Norwegian State is the majority shareholder of Statoil and also holds major investments in other Norwegian companies. As of 31 December 2015 the Norwegian State had an ownership interest in Statoil of 67.0% (excluding Folketrygdfondet, the Norwegian national insurance fund, of 3.2%). This ownership structure means that Statoil participates in transactions with many parties that are under a common ownership structure and therefore meet the definition of a related party. All transactions are considered to be on an arm's length basis.

Total purchases of oil and natural gas liquids from the Norwegian State amounted to NOK 60.0 billion, NOK 86.4 billion and NOK 92.5 billion in 2015, 2014 and 2013, respectively. Total purchases of natural gas regarding the Tjeldbergodden methanol plant from the Norwegian State amounted to NOK 0.6 billion, NOK 0.5 billion and NOK 0.5 billion in 2015, 2014 and 2013, respectively. In addition, Statoil ASA sells in its own name, but for the Norwegian State's account and risk, the Norwegian State's gas production. These transactions are presented net. For further information please see note 2 *Significant accounting policies*. The most significant items included in the line item equity accounted investments and other related party payables in note 21 *Trade and other payables*, are amounts payable to the Norwegian State for these purchases.

Other transactions

In relation to its ordinary business operations Statoil enters into contracts such as pipeline transport, gas storage and processing of petroleum products, with companies in which Statoil has ownership interests. Such transactions are carried out on an arm's length basis and are included within the applicable captions in the Consolidated statement of income. Gassled and certain other infrastructure assets are operated by Gassco AS, which is an entity under common control by the Norwegian Ministry of Petroleum and Energy. Gassco's activities are performed on behalf of and for the risk and reward of pipeline and terminal owners, and capacity payments flow through Gassco to the respective owners. Statoil payments that flowed through Gassco in this respect amounted to NOK 7.2 billion, NOK 7.4 billion and NOK 7.3 billion in 2015, 2014 and 2013, respectively.

For information concerning certain lease arrangements with Statoil Pension, see note 22 *Leases*.

Related party transactions with management are presented in note 6 *Remuneration*. Management remuneration for 2015 is presented in note 5 *Remuneration* in the financial statements of the parent company, Statoil ASA.

25 Financial instruments: fair value measurement and sensitivity analysis of market risk

Financial instruments by category

The following tables present Statoil's classes of financial instruments and their carrying amounts by the categories as they are defined in IAS 39 *Financial Instruments: Recognition and Measurement*. All financial instruments' carrying amounts are measured at fair value or their carrying amounts reasonably approximate fair value except non-current financial liabilities. See note 18 *Finance debt* for fair value information of non-current bonds, bank loans and finance lease liabilities.

See note 2 *Significant accounting policies* for further information regarding measurement of fair values.

				Fair value through profit or loss			
(in NOK billion)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2015							
Assets							
Non-current derivative financial instruments		0.0	0.0	23.8	0.0	0.0	23.8
Non-current financial investments	13	0.0	1.8	0.0	18.7	0.0	20.6
Prepayments and financial receivables	13	5.8	0.0	0.0	0.0	2.8	8.5
Trade and other receivables	15	51.4	0.0	0.0	0.0	7.4	58.8
Current derivative financial instruments		0.0	0.0	4.8	0.0	0.0	4.8
Current financial investments	13	19.1	0.0	61.4	6.0	0.0	86.5
Cash and cash equivalents	16	27.1	0.0	48.8	0.0	0.0	76.0
Total		103.4	1.9	138.8	24.7	10.1	278.8

				Fair value through profit or loss			
(in NOK billion)	Note	Loans and receivables	Available for sale	Held for trading	Fair value option	Non-financial assets	Total carrying amount
At 31 December 2014							
Assets							
Non-current derivative financial instruments		0.0	0.0	29.9	0.0	0.0	29.9
Non-current financial investments	13	0.0	1.4	0.0	18.2	0.0	19.6
Prepayments and financial receivables	13	2.7	0.0	0.0	0.0	2.9	5.7
Trade and other receivables	15	73.7	0.0	0.0	0.0	9.6	83.3
Current derivative financial instruments		0.0	0.0	5.3	0.0	0.0	5.3
Current financial investments	13	9.8	0.0	43.4	6.0	0.0	59.2
Cash and cash equivalents	16	48.9	0.0	34.2	0.0	0.0	83.1
Total		135.2	1.4	112.8	24.2	12.6	286.2

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2015					
Liabilities					
Non-current finance debt	18	264.0	0.0	0.0	264.0
Non-current derivative financial instruments		0.0	11.3	0.0	11.3
Trade and other payables	21	66.8	0.0	15.4	82.2
Current finance debt	18	20.5	0.0	0.0	20.5
Dividend payable		6.2	0.0	0.0	6.2
Current derivative financial instruments		0.0	2.3	0.0	2.3
Total		357.5	13.6	15.4	386.5

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2014					
Liabilities					
Non-current finance debt	18	205.1	0.0	0.0	205.1
Non-current derivative financial instruments		0.0	4.5	0.0	4.5
Trade and other payables	21	82.5	0.0	18.1	100.7
Current finance debt	18	26.5	0.0	0.0	26.5
Dividend payable		5.7	0.0	0.0	5.7
Current derivative financial instruments		0.0	6.6	0.0	6.6
Total		319.8	11.1	18.1	349.1

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the Consolidated balance sheet at fair value, split by Statoil's basis for fair value measurement.

(in NOK billion)	Non-current financial investments	Non-current derivative financial instruments - assets	Current financial investments	Current derivative financial instruments - assets	Cash equivalents	Non-current derivative financial instruments - liabilities	Current derivative financial instruments - liabilities	Net fair value
At 31 December 2015								
Level 1	10.5	0.0	4.8	0.0	0.0	0.0	0.0	15.3
Level 2	8.2	15.5	62.6	4.3	48.8	(10.8)	(2.3)	126.3
Level 3	1.8	8.3	0.0	0.4	0.0	(0.5)	0.0	10.1
Total fair value	20.6	23.8	67.4	4.8	48.8	(11.3)	(2.3)	151.7
At 31 December 2014								
Level 1	11.1	0.0	4.0	0.0	0.0	0.0	0.0	15.1
Level 2	7.0	17.2	45.5	4.7	34.2	(4.5)	(6.6)	97.4
Level 3	1.4	12.7	0.0	0.6	0.0	0.0	(0.0)	14.7
Total fair value	19.6	29.9	49.4	5.3	34.2	(4.5)	(6.6)	127.3

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, includes financial instruments actively traded and for which the values recognised in the Consolidated balance sheet are determined based on observable prices on identical instruments. For Statoil this category will, in most cases, only be relevant for investments in listed equity securities and government bonds.

Level 2, fair value based on inputs other than quoted prices included within level 1, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are determined on the basis of price inputs from observable market transactions. This will typically be when

Statoil uses forward prices on crude oil, natural gas, interest rates and foreign exchange rates as inputs to the valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, includes financial instruments for which fair values are determined on the basis of input and assumptions that are not from observable market transactions. The fair values presented in this category are mainly based on internal assumptions. The internal assumptions are only used in the absence of quoted prices from an active market or other observable price inputs for the financial instruments subject to the valuation.

The fair value of certain earn-out agreements and embedded derivative contracts are determined by the use of valuation techniques with price inputs from observable market transactions as well as internally generated price assumptions and volume profiles. The discount rate used in the valuation is a risk-free rate based on the applicable currency and time horizon of the underlying cash flows adjusted for a credit premium to reflect either Statoil's credit premium, if the value is a liability, or an estimated counterparty credit premium if the value is an asset. In addition a risk premium for risk elements not adjusted for in the cash flow may be included when applicable. The fair values of these derivative financial instruments have been classified in their entirety in the third category within current derivative financial instruments and non-current derivative financial instruments - assets in the table above. Another reasonable assumption, that could have been applied when determining the fair value of these contracts, would be to extrapolate the last observed forward prices with inflation. If Statoil had applied this assumption, the fair value of the contracts included would have decreased by approximately NOK 4.6 billion at end of 2015 and decreased by NOK 3.5 billion at end of 2014 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2015 and 2014 for all financial assets classified in the third level in the hierarchy are presented in the following table.

(in NOK billion)	Non-current financial investments	Non-current derivative financial instruments - assets	Current derivative financial instruments - assets	Non-current derivative financial instruments liabilities	Total amount
Full year 2015					
Opening balance	1.4	12.7	0.6	0.0	14.8
Total gains and losses recognised					
- in statement of income	(0.0)	(3.6)	0.4	(0.5)	(3.6)
- in other comprehensive income	0.0	0.0	0.0	0.0	0.0
Purchases	0.2	0.0	0.0	0.0	0.2
Settlement	(0.0)	(0.9)	(0.6)	0.0	(1.5)
Foreign currency translation differences	0.2	0.1	(0.0)	(0.0)	0.2
Closing balance	1.8	8.3	0.4	(0.5)	10.1
Full year 2014					
Opening balance	0.9	12.0	1.3	0.0	14.2
Total gains and losses recognised					
- in statement of income	(0.0)	0.3	0.6	0.0	0.9
- in other comprehensive income	0.0	0.0	0.0	0.0	0.0
Purchases	0.3	0.0	0.0	0.0	0.3
Sales	0.0	0.4	0.0	0.0	0.4
Settlement	(0.0)	0.0	(1.3)	0.0	(1.3)
Foreign currency translation differences	0.2	0.1	(0.0)	0.0	0.3
Closing balance	1.4	12.7	0.6	0.0	14.8

The assets within level 3 during 2015 have had a net decrease in the fair value of NOK 4.7 billion. Of the NOK 3.1 billion recognised in the Consolidated statement of income during 2015, NOK 2.8 billion is related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements, NOK 1.5 billion included in the opening balance for 2015 has been fully realised as the underlying volumes have been delivered during 2015 and the amount is presented as settled in the above table.

Substantially all gains and losses recognised in the Consolidated statement of income during 2015 are related to assets held at the end of 2015.

Sensitivity analysis of market risk

Commodity price risk
The table below contains the fair value and related commodity price risk sensitivities of Statoil's commodity based derivatives contracts. For further information related to the type of commodity risks and how Statoil manages these risks, see note 5 *Financial risk management*.

Statoil's assets and liabilities resulting from commodity based derivatives contracts consist of both exchange traded and non-exchange traded instruments, including embedded derivatives that have been bifurcated and recognised at fair value in the Consolidated balance sheet.

Price risk sensitivities at the end of 2015 have been calculated assuming a reasonably possible change of 30% in crude oil, refined products, electricity and natural gas prices. At the end of 2014 an assumption of 40% was used in the calculation and viewed as reasonable possible changes.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value would be recognised in the Consolidated statement of income.

(in NOK billion)	- 30% sensitivity	30% sensitivity
At 31 December 2015		
Crude oil and refined products net gains (losses)	1.0	(0.6)
Natural gas and electricity net gains (losses)	3.0	(3.0)

(in NOK billion)	- 40% sensitivity	40% sensitivity
At 31 December 2014		
Crude oil and refined products net gains (losses)	(1.7)	1.8
Natural gas and electricity net gains (losses)	0.7	(0.7)

Currency risk

Currency risk constitutes significant financial risk for Statoil. In accordance with approved strategies and mandates total exposure is managed at a portfolio level on a regular basis. For further information related to the currency risk and how Statoil manages these risks, see note 5 *Financial risk management*.

The following currency risk sensitivity has been calculated by assuming an 11% reasonably possible change in the main foreign exchange rates that Statoil is exposed to. At the end of 2014 a change of 9% in the foreign exchange rates were viewed as reasonably possible changes. An increase in the foreign exchange rates means that the transaction currency has strengthened in value. The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the Consolidated statement of income.

(in NOK billion)	- 11% sensitivity	11% sensitivity
At 31 December 2015		
USD net gains (losses)	15.4	(15.4)
NOK net gains (losses)	(14.8)	14.8

(in NOK billion)	- 9% sensitivity	9% sensitivity
At 31 December 2014		
USD net gains (losses)	8.1	(8.1)
NOK net gains (losses)	(8.3)	8.3

Interest rate risk

Interest rate risk constitutes significant financial risk for Statoil. In accordance with approved strategies and mandates total exposure is managed at a portfolio level on a regular basis. For further information related to the interest risks and how Statoil manages these risks, see note 5 *Financial risk management*.

The following interest rate risk sensitivity has been calculated by assuming a change of 0.9 percentage points as reasonably possible changes in the interest rates at the end of 2015. At the end of 2014 a change of 0.8 percentage points in the interest rates was viewed as reasonably possible changes. The estimated gains following from a decrease in the interest rates and the estimated losses following from an interest rate increase would impact the Consolidated statement of income.

(in NOK billion)	- 0.9 percentage points sensitivity	0.9 percentage points sensitivity
At 31 December 2015		
Interest rate net gains (losses)	10.7	(10.7)

(in NOK billion)	- 0.8 percentage points sensitivity	0.8 percentage points sensitivity
At 31 December 2014		
Interest rate net gains (losses)	7.1	(7.1)

26 Condensed consolidated financial information related to guaranteed debt securities

Statoil Petroleum AS, a 100% owned subsidiary of Statoil ASA, is the co-obligor of certain existing debt securities of Statoil ASA that are registered under the US Securities Act of 1933 ("US registered debt securities"). As co-obligor, Statoil Petroleum AS fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil ASA, the payment and covenant obligations for these US registered debt securities. In addition, Statoil ASA is also the co-obligor of a US registered debt security of Statoil Petroleum AS. As co-obligor, Statoil ASA fully, unconditionally and irrevocably assumes and agrees to perform, jointly and severally with Statoil Petroleum AS, the payment and covenant obligations of that security. In the future, Statoil ASA may from time to time issue future US registered debt securities for which Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidated basis provides financial information about Statoil ASA, as issuer and co-obligor, Statoil Petroleum AS, as co-obligor and guarantor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X. The condensed consolidated information is prepared in accordance with Statoil's IFRS accounting policies as described in note 2 *Significant accounting policies*, except that investments in subsidiaries and jointly controlled entities are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information for the full year 2015, 2014 and 2013, and as of 31 December 2015 and 2014.

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	316.0	165.6	165.6	(164.1)	483.1
Net income from equity accounted companies	(33.7)	(66.1)	(0.4)	99.9	(0.3)
Total revenues and other income	282.3	99.5	165.2	(64.2)	482.8
Total operating expenses	(316.4)	(101.0)	(215.7)	165.2	(467.9)
Net operating income	(34.1)	(1.5)	(50.5)	101.0	14.9
Net financial items	(22.5)	(0.8)	1.1	11.6	(10.6)
Income before tax	(56.6)	(2.3)	(49.3)	112.6	4.3
Income tax	7.5	(42.7)	(6.4)	(0.1)	(41.6)
Net income	(49.1)	(45.0)	(55.7)	112.5	(37.3)
Other comprehensive income	46.3	18.3	56.4	(86.3)	34.7
Total comprehensive income	(2.8)	(26.7)	0.7	26.2	(2.6)

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	411.1	210.8	213.7	(212.7)	622.9
Net income from equity accounted companies	21.6	(32.7)	(0.2)	11.0	(0.3)
Total revenues and other income	432.8	178.1	213.4	(201.6)	622.7
Total operating expenses	(417.8)	(89.1)	(222.4)	216.0	(513.2)
Net operating income	15.0	89.0	(8.9)	14.4	109.5
Net financial items	(12.6)	0.0	(0.4)	12.9	(0.0)
Income before tax	2.4	89.0	(9.3)	27.3	109.4
Income tax	6.6	(81.3)	(11.5)	(1.2)	(87.4)
Net income	9.0	7.7	(20.8)	26.0	22.0
Other comprehensive income	55.4	26.0	70.5	(109.3)	42.5
Total comprehensive income	64.4	33.7	49.7	(83.3)	64.5

CONDENSED CONSOLIDATED STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

Full year 2013 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	416.7	228.8	212.1	(223.2)	634.4
Net income from equity accounted companies	55.0	(8.0)	(0.2)	(46.6)	0.1
Total revenues and other income	471.7	220.8	211.9	(269.8)	634.5
Total operating expenses	(418.3)	(85.5)	(199.0)	223.6	(479.1)
Net operating income	53.5	135.3	12.9	(46.2)	155.5
Net financial items	(27.7)	(1.0)	5.9	5.7	(17.0)
Income before tax	25.8	134.3	18.8	(40.5)	138.4
Income tax	8.1	(95.3)	(11.7)	(0.2)	(99.2)
Net income	33.9	39.0	7.1	(40.7)	39.2
Other comprehensive income	24.2	5.0	27.6	(38.2)	18.5
Total comprehensive income	58.1	44.0	34.7	(78.9)	57.7

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.6	261.2	363.0	(0.3)	629.5
Equity accounted companies	472.5	181.0	3.8	(650.1)	7.3
Other non-current assets	38.4	8.9	34.7	0.0	82.0
Non-current receivables from subsidiaries	123.1	0.0	0.2	(123.3)	0.0
Total non-current assets	639.6	451.1	401.7	(773.8)	718.7
Current receivables from subsidiaries	10.9	20.4	120.1	(151.4)	(0.0)
Other current assets	130.8	8.9	36.3	(3.9)	172.1
Cash and cash equivalents	65.8	0.8	9.4	0.0	76.0
Total current assets	207.5	30.1	165.7	(155.3)	248.0
Total assets	847.2	481.2	567.4	(929.1)	966.7
EQUITY AND LIABILITIES					
Total equity	354.7	184.1	463.4	(647.2)	355.1
Non-current liabilities to subsidiaries	0.1	120.9	2.3	(123.3)	0.0
Other non-current liabilities	303.2	126.5	47.9	(1.2)	476.3
Total non-current liabilities	303.3	247.4	50.1	(124.5)	476.3
Other current liabilities	52.5	38.6	50.3	(6.0)	135.3
Current liabilities to subsidiaries	136.7	11.1	3.6	(151.4)	0.0
Total current liabilities	189.1	49.7	53.9	(157.4)	135.3
Total liabilities	492.4	297.1	104.0	(281.9)	611.7
Total equity and liabilities	847.2	481.2	567.4	(929.1)	966.7

CONDENSED CONSOLIDATED BALANCE SHEET

At 31 December 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.9	276.4	365.3	(0.4)	647.3
Equity accounted companies	490.0	140.5	7.5	(629.6)	8.4
Other non-current assets	34.8	13.0	28.2	0.0	76.0
Non-current receivables from subsidiaries	68.6	0.4	0.2	(69.2)	0.0
Total non-current assets	599.3	430.3	401.2	(699.2)	731.7
Current receivables from subsidiaries	16.1	50.3	89.0	(155.4)	0.0
Other current assets	116.7	14.2	46.8	(6.0)	171.6
Cash and cash equivalents	71.5	0.6	11.0	0.0	83.1
Total current assets	204.4	65.0	146.7	(161.4)	254.8
Total assets	803.8	495.4	547.9	(860.6)	986.4
EQUITY AND LIABILITIES					
Total equity	380.8	215.1	412.4	(627.1)	381.2
Non-current liabilities to subsidiaries	0.1	66.3	2.7	(69.2)	0.0
Other non-current liabilities	238.2	144.9	45.3	(2.3)	426.2
Total non-current liabilities	238.4	211.2	48.0	(71.4)	426.2
Other current liabilities	68.1	60.0	57.6	(6.7)	179.0
Current liabilities to subsidiaries	116.5	9.1	29.8	(155.4)	0.0
Total current liabilities	184.6	69.1	87.4	(162.1)	179.0
Total liabilities	423.0	280.3	135.5	(233.5)	605.2
Total equity and liabilities	803.8	495.4	547.9	(860.6)	986.4

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

Full year 2015 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	23.5	64.7	37.4	(16.6)	109.0
Cash flows provided by (used in) investing activities	(44.8)	(141.3)	(46.9)	117.9	(115.1)
Cash flows provided by (used in) financing activities	9.9	76.7	7.2	(101.3)	(7.5)
Net increase (decrease) in cash and cash equivalents	(11.5)	0.1	(2.3)	0.0	(13.6)
Effect of exchange rate changes on cash and cash equivalents	5.7	0.1	1.3	0.0	7.1
Cash and cash equivalents at the beginning of the period (net of overdraft)	71.5	0.6	10.3	0.0	82.4
Cash and cash equivalents at the end of the period (net of overdraft)	65.8	0.8	9.3	0.0	75.9

Full year 2014 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	18.6	73.2	56.9	(22.2)	126.5
Cash flows provided by (used in) investing activities	(16.9)	(59.4)	(55.5)	19.8	(112.0)
Cash flows provided by (used in) financing activities	(11.0)	(13.2)	(1.3)	2.4	(23.1)
Net increase (decrease) in cash and cash equivalents	(9.3)	0.6	0.1	0.0	(8.6)
Effect of exchange rate changes on cash and cash equivalents	3.8	0.1	1.9	0.0	5.8
Cash and cash equivalents at the beginning of the period (net of overdraft)	77.0	0.0	8.3	0.0	85.3
Cash and cash equivalents at the end of the period (net of overdraft)	71.5	0.7	10.3	0.0	82.5

Full year 2013 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	64.3	69.9	39.6	(72.6)	101.3
Cash flows provided by (used in) investing activities	(46.9)	(46.0)	(87.4)	69.9	(110.4)
Cash flows provided by (used in) financing activities	(0.6)	(23.9)	48.5	2.7	26.6
Net increase (decrease) in cash and cash equivalents	16.8	0.0	0.7	0.0	17.5
Effect of exchange rate changes on cash and cash equivalents	2.7	0.0	0.2	0.0	2.9
Cash and cash equivalents at the beginning of the period (net of overdraft)	57.4	0.0	7.5	0.0	64.9
Cash and cash equivalents at the end of the period (net of overdraft)	77.0	0.0	8.3	0.0	85.3

27 Supplementary oil and gas information (unaudited)

In accordance with Financial Accounting Standards Board Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is reporting certain supplemental disclosures about oil and gas exploration and production operations. While this information is developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgement involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of Statoil or its expected future results.

For further information regarding the reserves estimation requirement, see note 2 *Significant accounting policies* - Critical accounting judgements and key sources of estimation uncertainty - Proved oil and gas reserves.

No new events have occurred since 31 December 2015 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

The disputed equity determination at Agbami will potentially alter Statoil's equity share in this field. The effect on the proved reserves will be included once the redetermination is finalised and the effect is known.

Oil and gas reserve quantities

Statoil's oil and gas reserves have been estimated by its qualified professionals in accordance with industry standards under the requirements of the U.S. Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. Statements of reserves are forward-looking statements.

The determination of these reserves is part of an ongoing process subject to continual revision as additional information becomes available. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, identified reserves and contingent resources that may become proved in the future are excluded from the calculations.

Statoil's proved reserves are recognised under various forms of contractual agreements, including production sharing agreements (PSAs) where Statoil's share of reserves can vary due to commodity prices or other factors. Reserves from agreements such as PSAs and buy back agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2015, 9% of total proved reserves were related to such agreements (15% of total oil, condensate and natural gas liquids (NGL) reserves and 3% of total gas reserves). This compares with 12% and 14% of total proved reserves for 2014 and 2013, respectively. Net entitlement oil and gas production from fields with such agreements was 104 million boe during 2015 (95 million boe for 2014 and 93 million boe for 2013). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil. Reserves are net of royalty oil paid in kind and quantities consumed during production.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on existing economic conditions, including a 12-month average price prior to the end of the reporting period, unless prices are defined by contractual arrangements. The proved reserves at year end 2015 have been determined based on a Brent blend price equivalent of USD 54.17/bbl, compared to USD 101.27/bbl and USD 108.02/bbl for 2014 and 2013 respectively. The volume weighted average gas price for proved reserves at year end 2015 was 1.76 NOK/Sm3. The comparable gas price used to determine gas reserves at year end 2014 and 2013 was 1.90 NOK/Sm3 and 2.13 NOK/Sm3. The volume weighted average NGL price for proved reserves at year end 2015 was USD 30.56/boe. The corresponding NGL price used to determine NGL reserves at year end 2014 and 2013 was USD 57.03/boe and USD 62.32/boe. The significant decrease in commodity prices affects the profitable reserves to be recovered from accumulations resulting in reduced reserves. The negative revisions due to price are in general a result of earlier economic cut-off. For fields with a production-sharing type of agreement this is to some degree offset by higher entitlement to the reserves. These changes are all included in the revision category in the tables below, giving a net reduction of Statoil's proved reserves at year end.

From the Norwegian continental shelf (NCS), Statoil is responsible for managing, transporting and selling the Norwegian State's oil and gas on behalf of the Norwegian State's direct financial interest (SDFI). These reserves are sold in conjunction with the Statoil reserves. As part of this arrangement, Statoil delivers and sells gas to customers in accordance with various types of sales contracts on behalf of the SDFI. In order to fulfil the commitments, Statoil utilises a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between Statoil and the SDFI.

Statoil and the SDFI receive income from the joint natural gas sales portfolio based upon their respective share in the supplied volumes. For sales of the SDFI natural gas, to Statoil and to third parties, the payment to the Norwegian State is based on achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. The price Statoil pays to the SDFI for the crude oil is based on market reflective prices. The prices for NGL are either based on achieved prices, market value or market reflective prices.

The regulations of the owner's instruction, as described above, may be changed or withdrawn by the Statoil ASA's general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographical area, defined as country or continent containing 15% or more of total proved reserves. Norway contains 75% of total proved reserves at 31 December 2015 and no other country contains reserves approaching 15% of total proved reserves. Accordingly, management has determined that the most meaningful presentation of geographical areas would be Norway and the continents of Eurasia (excluding Norway), Africa and Americas.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2012 through 2015, and the changes therein.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and condensate reserves in million barrels oil equivalent							
At 31 December 2012	968	193	281	395	1,837	82	1,919
Revisions and improved recovery	133	16	40	18	207	(16)	191
Extensions and discoveries	19	47	8	34	108	0	108
Purchase of reserves-in-place	13	0	0	0	13	0	13
Sales of reserves-in-place	(40)	(15)	0	(2)	(57)	0	(57)
Production	(174)	(15)	(58)	(46)	(294)	(4)	(298)
At 31 December 2013	918	227	271	399	1,815	63	1,877
Revisions and improved recovery	143	10	85	(4)	235	(3)	232
Extensions and discoveries	3	0	5	145	153	0	153
Purchase of reserves-in-place	0	0	0	20	20	0	20
Sales of reserves-in-place	(5)	(27)	(2)	0	(34)	0	(34)
Production	(173)	(14)	(64)	(51)	(301)	(4)	(306)
At 31 December 2014	886	196	296	508	1,887	55	1,942
Revisions and improved recovery	71	(68)	57	(54)	5	(5)	0
Extensions and discoveries	437	0	0	74	511	0	511
Purchase of reserves-in-place	0	0	0	4	4	0	4
Sales of reserves-in-place	(4)	(38)	0	(1)	(43)	0	(43)
Production	(174)	(13)	(75)	(57)	(319)	(4)	(324)
At 31 December 2015	1,216	76	278	474	2,045	46	2,091

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved NGL reserves in million barrels oil equivalent							
At 31 December 2012	405	0	18	47	469	0	469
Revisions and improved recovery	25	0	(0)	4	28	0	28
Extensions and discoveries	1	0	0	10	11	0	11
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(21)	0	0	0	(21)	0	(21)
Production	(42)	0	(1)	(4)	(47)	0	(47)
At 31 December 2013	368	0	16	56	441	0	441
Revisions and improved recovery	(2)	0	1	5	4	0	4
Extensions and discoveries	3	0	0	18	21	0	21
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(10)	0	0	(2)	(12)	0	(12)
Production	(42)	0	(2)	(7)	(51)	0	(51)
At 31 December 2014	318	0	15	69	403	0	403
Revisions and improved recovery	7	0	3	(20)	(10)	0	(10)
Extensions and discoveries	11	0	0	16	27	0	27
Purchase of reserves-in-place	0	0	0	4	4	0	4
Sales of reserves-in-place	(1)	0	0	(5)	(5)	0	(5)
Production	(44)	0	(3)	(7)	(54)	0	(54)
At 31 December 2015	291	0	15	57	364	0	364

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved gas reserves in billion standard cubic feet							
At 31 December 2012	15,003	575	341	1,107	17,027	0	17,027
Revisions and improved recovery	391	187	27	382	987	0	987
Extensions and discoveries	920	1,236	0	112	2,268	0	2,268
Purchase of reserves-in-place	5	0	0	0	5	0	5
Sales of reserves-in-place	(295)	(3)	0	(2)	(300)	0	(300)
Production	(1,264)	(72)	(40)	(196)	(1,571)	0	(1,571)
At 31 December 2013	14,761	1,923	328	1,404	18,416	0	18,416
Revisions and improved recovery	439	32	8	197	676	0	676
Extensions and discoveries	79	0	0	364	443	0	443
Purchase of reserves-in-place	0	0	0	0	0	0	0
Sales of reserves-in-place	(355)	(681)	0	(15)	(1,051)	0	(1,051)
Production	(1,229)	(56)	(38)	(242)	(1,565)	0	(1,565)
At 31 December 2014	13,694	1,218	299	1,708	16,919	0	16,919
Revisions and improved recovery	385	(18)	129	(676)	(180)	0	(180)
Extensions and discoveries	179	0	0	318	497	0	497
Purchase of reserves-in-place	0	0	0	31	31	0	31
Sales of reserves-in-place	(10)	(991)	0	(42)	(1,043)	0	(1,043)
Production	(1,306)	(16)	(63)	(215)	(1,600)	0	(1,600)
At 31 December 2015	12,942	193	366	1,123	14,624	0	14,624

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved reserves in million barrels oil equivalent							
At 31 December 2012	4,046	296	360	639	5,340	82	5,422
Revisions and improved recovery	227	49	44	90	411	(16)	395
Extensions and discoveries	183	268	8	64	523	0	523
Purchase of reserves-in-place	14	0	0	0	14	0	14
Sales of reserves-in-place	(113)	(15)	0	(2)	(131)	0	(131)
Production	(441)	(28)	(66)	(85)	(621)	(4)	(625)
At 31 December 2013	3,916	569	346	705	5,537	63	5,600
Revisions and improved recovery	219	16	87	36	359	(3)	356
Extensions and discoveries	20	0	5	227	253	0	253
Purchase of reserves-in-place	0	0	0	20	20	0	20
Sales of reserves-in-place	(78)	(148)	(2)	(5)	(233)	0	(233)
Production	(434)	(24)	(72)	(102)	(631)	(4)	(635)
At 31 December 2014	3,644	413	364	882	5,304	55	5,359
Revisions and improved recovery	146	(72)	83	(194)	(37)	(5)	(42)
Extensions and discoveries	480	0	0	146	627	0	627
Purchase of reserves-in-place	0	0	0	13	13	0	13
Sales of reserves-in-place	(6)	(215)	0	(13)	(235)	0	(235)
Production	(450)	(16)	(88)	(103)	(658)	(4)	(662)
At 31 December 2015	3,814	111	358	731	5,014	46	5,060

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and condensate reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	547	79	221	164	1,010	38	1,049
Undeveloped	421	114	61	231	827	44	870
At 31 December 2013							
Developed	548	63	197	212	1,020	32	1,052
Undeveloped	370	164	74	187	795	30	826
At 31 December 2014							
Developed	559	63	243	267	1,133	24	1,156
Undeveloped	327	133	52	242	754	32	786
At 31 December 2015							
Developed	505	48	248	282	1,083	21	1,104
Undeveloped	711	29	30	192	962	25	987
Net proved NGL reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	296	0	11	27	334	0	334
Undeveloped	109	0	7	20	135	0	135
At 31 December 2013							
Developed	287	0	10	34	330	0	330
Undeveloped	82	0	7	22	111	0	111
At 31 December 2014							
Developed	258	0	9	42	310	0	310
Undeveloped	60	0	6	27	93	0	93
At 31 December 2015							
Developed	235	0	9	45	290	0	290
Undeveloped	56	0	6	12	74	0	74
Net proved gas reserves in billion standard cubic feet							
At 31 December 2012							
Developed	12,073	343	226	567	13,210	0	13,210
Undeveloped	2,931	232	115	540	3,817	0	3,817
At 31 December 2013							
Developed	11,580	467	209	817	13,073	0	13,073
Undeveloped	3,181	1,455	120	586	5,343	0	5,343
At 31 December 2014							
Developed	11,227	312	191	946	12,677	0	12,677
Undeveloped	2,467	906	108	762	4,242	0	4,242
At 31 December 2015							
Developed	10,664	32	206	999	11,901	0	11,901
Undeveloped	2,278	161	160	124	2,723	0	2,723
Net proved oil, condensate, NGL and gas reserves in million barrels oil equivalent							
At 31 December 2012							
Developed	2,994	140	272	292	3,698	38	3,737
Undeveloped	1,052	155	88	347	1,642	44	1,686
At 31 December 2013							
Developed	2,898	146	244	392	3,679	32	3,711
Undeveloped	1,018	423	103	314	1,858	30	1,888
At 31 December 2014							
Developed	2,818	119	287	477	3,701	24	3,725
Undeveloped	826	295	78	405	1,603	32	1,635
At 31 December 2015							
Developed	2,641	53	294	505	3,494	21	3,515
Undeveloped	1,173	57	64	226	1,521	25	1,546

The conversion rates used are 1 standard cubic meter = 35.3 standard cubic feet, 1 standard cubic meter oil equivalent = 6.29 barrels of oil equivalent (boe) and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

Capitalised cost related to oil and gas producing activities

Consolidated companies

(in NOK billion)	2015	2014	At 31 December 2013
Unproved properties	117.5	97.5	83.8
Proved properties, wells, plants and other equipment	1,327.1	1,178.8	984.1
Total capitalised cost	1,444.6	1,276.3	1,068.0
Accumulated depreciation, impairment and amortisation	(873.1)	(687.2)	(543.7)
Net capitalised cost	571.5	589.1	524.3

Net capitalised cost related to equity accounted investments as of 31 December 2015 was NOK 8.8 billion, NOK 7.2 billion in 2014 and NOK 5.9 billion in 2013. The reported figures are based on capitalised costs within the upstream segments in Statoil, in line with the description below for result of operations for oil and gas producing activities.

Expenditures incurred in oil and gas property acquisition, exploration and development activities

These expenditures include both amounts capitalised and expensed.

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2015					
Exploration expenditures	6.4	1.7	3.0	12.0	23.1
Development costs	47.1	11.4	10.5	29.0	98.1
Acquired proved properties	0.0	0.0	0.0	0.7	0.7
Acquired unproved properties	0.0	0.7	0.7	3.1	4.5
Total	53.5	13.7	14.3	44.8	126.3
Full year 2014					
Exploration expenditures	7.0	2.5	7.3	7.1	23.9
Development costs	52.2	13.4	13.3	22.7	101.7
Acquired proved properties	0.0	0.0	0.0	4.7	4.7
Acquired unproved properties	0.0	0.0	0.0	2.3	2.3
Total	59.3	15.9	20.6	36.8	132.5
Full year 2013					
Exploration expenditures	7.9	3.8	2.7	7.4	21.8
Development costs	51.8	8.5	11.6	26.4	98.3
Acquired proved properties	2.2	0.0	0.0	0.0	2.2
Acquired unproved properties	0.0	0.4	0.0	1.8	2.2
Total	61.9	12.7	14.3	35.6	124.5

Expenditures incurred in development activities related to equity accounted investments was NOK 0.4 billion in 2015, NOK 1.6 billion in 2014 and NOK 0.4 billion in 2013.

Results of operation for oil and gas producing activities
As required by Topic 932, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of Statoil.

The result of operations for oil and gas producing activities contains the two upstream reporting segments Development and Production Norway (DPN) and Development and Production International (DPI) as presented in note 3 *Segments*. Production cost is based on operating expenses related to production of oil and gas. From the operating expenses certain expenses such as; transportation costs, accruals for over/underlift position, royalty payments and diluent costs are excluded. These expenses and mainly upstream business administration are included as other expenses in the tables below. Other revenues mainly consist of gains and losses from sales of oil and gas interests and gains and losses from commodity based derivatives within the upstream segments.

Income tax expense is calculated on the basis of statutory tax rates adjusted for uplift and tax credits. No deductions are made for interest or other elements not included in the table below.

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2015					
Sales	0.4	2.0	(0.6)	1.6	3.5
Transfers	140.1	3.8	27.7	22.2	193.9
Other revenues	(1.0)	12.3	0.0	0.1	11.4
Total revenues	139.5	18.2	27.2	23.9	208.7
Exploration expenses	(4.6)	(1.7)	(5.1)	(19.5)	(31.0)
Production costs	(21.1)	(1.3)	(5.4)	(6.4)	(34.2)
Depreciation, amortisation and net impairment losses	(51.4)	(6.4)	(20.1)	(55.1)	(133.0)
Other expenses	(4.7)	(1.3)	(1.9)	(11.1)	(19.0)
Total costs	(81.9)	(10.7)	(32.6)	(92.0)	(217.2)
Results of operations before tax	57.6	7.4	(5.4)	(68.2)	(8.5)
Tax expense	(38.8)	1.8	(5.4)	(0.2)	(42.6)
Results of operations	18.8	9.2	(10.8)	(68.3)	(51.1)
Net income from equity accounted investments	0.0	0.3	0.0	(1.0)	(0.8)

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2014					
Sales	1.8	4.3	5.0	3.9	15.0
Transfers	172.6	6.1	32.6	28.6	239.9
Other revenues	7.7	5.7	0.7	(1.0)	13.1
Total revenues	182.1	16.1	38.3	31.4	268.1
Exploration expenses	(5.4)	(2.6)	(9.2)	(13.2)	(30.3)
Production costs	(23.0)	(1.5)	(4.6)	(5.3)	(34.4)
Depreciation, amortisation and net impairment losses	(40.0)	(4.9)	(14.1)	(37.9)	(96.9)
Other expenses	(2.2)	(1.2)	0.4	(10.6)	(13.6)
Total costs	(70.5)	(10.1)	(27.5)	(67.0)	(175.2)
Results of operations before tax	111.6	6.0	10.9	(35.6)	92.9
Tax expense	(74.8)	(0.5)	(8.4)	(0.4)	(84.0)
Results of operations	36.8	5.5	2.5	(36.0)	8.8
Net income from equity accounted investments	(0.0)	1.0	0.0	(1.7)	(0.7)

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Full year 2013					
Sales	0.3	4.0	3.9	4.1	12.3
Transfers	192.5	7.4	30.9	27.1	257.9
Other revenues	9.3	3.9	0.2	0.4	13.8
Total revenues	202.1	15.3	35.0	31.6	284.0
Exploration expenses	(5.5)	(3.4)	(1.6)	(7.5)	(18.0)
Production costs	(22.1)	(1.5)	(3.9)	(3.9)	(31.4)
Depreciation, amortisation and net impairment losses	(32.2)	(2.4)	(13.3)	(16.2)	(64.1)
Other expenses	(5.3)	(1.6)	(0.5)	(9.7)	(17.1)
Total costs	(65.1)	(8.9)	(19.3)	(37.3)	(130.6)
Results of operations before tax	137.0	6.4	15.7	(5.7)	153.4
Tax expense	(90.9)	(2.0)	(8.1)	(1.0)	(102.0)
Results of operations	46.1	4.4	7.6	(6.7)	51.4
Net income from equity accounted investments	0.1	0.3	0.0	(0.3)	0.1

Average production cost in NOK per boe based on entitlement volumes	Norway	Eurasia excluding Norway	Africa	Americas	Total
2015	47	79	61	62	52
2014	53	64	64	52	55
2013	50	53	59	46	51

Production cost per boe is calculated as the production costs in the result of operations table, divided by the produced entitlement volumes (mboe) for the corresponding period.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves

The table below shows the standardised measure of future net cash flows relating to proved reserves. The analysis is computed in accordance with Topic 932, by applying average market prices as defined by the SEC, year end costs, year end statutory tax rates and a discount factor of 10% to year end quantities of net proved reserves. The standardised measure of discounted future net cash flows is a forward-looking statement.

Future price changes are limited to those provided by existing contractual arrangements at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Pre-tax future net cash flow is net of decommissioning and removal costs. Estimated future income taxes are calculated by applying the appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using a discount rate of 10% per year. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced. The standardised measure of discounted future net cash flows prescribed under Topic 932 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. The information does not represent management's estimate or Statoil's expected future cash flows or the value of its proved reserves and therefore should not be relied upon as an indication of Statoil's future cash flow or value of its proved reserves.

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2015					
Consolidated companies					
Future net cash inflows	1,288.7	43.9	137.3	189.7	1,659.5
Future development costs	(156.1)	(10.8)	(10.7)	(41.5)	(219.0)
Future production costs	(441.5)	(22.2)	(54.9)	(102.6)	(621.3)
Future income tax expenses	(455.7)	(0.9)	(25.3)	(6.4)	(488.4)
Future net cash flows	235.4	9.9	46.3	39.2	330.8
10% annual discount for estimated timing of cash flows	(96.6)	(3.3)	(11.1)	(15.8)	(126.8)
Standardised measure of discounted future net cash flows	138.8	6.6	35.2	23.4	203.9
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	1.1	1.1
Total standardised measure of discounted future net cash flows including equity accounted investments	138.8	6.6	35.2	24.5	205.1

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2014					
Consolidated companies					
Future net cash inflows	1,467.9	203.4	213.6	323.0	2,207.9
Future development costs	(166.8)	(59.9)	(12.3)	(51.7)	(290.8)
Future production costs	(439.8)	(91.6)	(58.3)	(142.7)	(732.4)
Future income tax expenses	(606.8)	(8.1)	(48.6)	(34.0)	(697.5)
Future net cash flows	254.5	43.8	94.4	94.6	487.3
10% annual discount for estimated timing of cash flows	(99.7)	(27.8)	(28.1)	(41.9)	(197.6)
Standardised measure of discounted future net cash flows	154.7	16.0	66.3	52.7	289.8
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	5.1	5.1
Total standardised measure of discounted future net cash flows including equity accounted investments	154.7	16.0	66.3	57.8	294.8

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2013					
Consolidated companies					
Future net cash inflows	1,700.2	273.7	205.2	257.5	2,436.6
Future development costs	(200.0)	(80.8)	(16.0)	(38.9)	(335.7)
Future production costs	(471.3)	(125.4)	(54.8)	(104.3)	(755.8)
Future income tax expenses	(740.9)	(12.2)	(50.0)	(24.0)	(827.1)
Future net cash flows	288.0	55.3	84.4	90.3	518.0
10% annual discount for estimated timing of cash flows	(120.8)	(39.7)	(27.6)	(41.3)	(229.4)
Standardised measure of discounted future net cash flows	167.2	15.6	56.8	49.0	288.6
Equity accounted investments					
Standardised measure of discounted future net cash flows	0,0	0,0	0,0	4.8	4.8
Total standardised measure of discounted future net cash flows including equity accounted investments	167.2	15.6	56.8	53.8	293.4

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK billion)	2015	2014	2013
Consolidated companies			
Standardised measure at beginning of year	289.8	288.6	252.8
Net change in sales and transfer prices and in production (lifting) costs related to future production	(313.7)	(98.3)	(24.0)
Changes in estimated future development costs	(4.5)	(32.3)	(54.9)
Sales and transfers of oil and gas produced during the period, net of production cost	(168.0)	(232.6)	(243.2)
Net change due to extensions, discoveries, and improved recovery	30.1	23.1	10.6
Net change due to purchases and sales of minerals in place	(7.4)	(25.1)	(33.9)
Net change due to revisions in quantity estimates	76.4	126.1	126.5
Previously estimated development costs incurred during the period	84.6	99.6	95.1
Accretion of discount	71.0	77.3	81.4
Net change in income taxes	145.7	63.3	78.2
Total change in the standardised measure during the year	(85.8)	1.2	35.8
Standardised measure at end of year	203.9	289.8	288.6
Equity accounted investments			
Standardised measure at end of year	1.1	5.1	4.8
Standardised measure at end of year including equity accounted investments	205.1	294.8	293.4

In the table above, each line item presents the sources of changes in the standardised measure value on a discounted basis, with the accretion of discount line item reflecting the increase in the net discounted value of the proved oil and gas reserves due to the fact that the future cash flows are now one year closer in time.

28 Subsequent events

In the first quarter of 2016 Statoil acquired 11.93% of the shares and votes in Lundin Petroleum AB for a total purchase price of SEK 4.6 billion. The shares will be accounted for as a non-current financial investment (available-for-sale) at fair value.

8.2 Report of Independent Registered Public Accounting firm

8.2.1 Report of Independent Registered Public Accounting firm

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited the accompanying consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2015 and 2014 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the three-year period ended 31 December 2015. These consolidated financial statements are the responsibility of Statoil ASA's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA and subsidiaries as of 31 December 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended 31 December 2015, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Statoil ASA's internal control over financial reporting as of 31 December 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 9 March 2016 expressed an unqualified opinion on the effectiveness of Statoil ASA's internal control over financial reporting.

/s/ KPMG AS

Trondheim, Norway
9 March 2016

8.2.2 Report of KPMG on Statoil's internal control over financial reporting

Report of Independent Registered Public Accounting Firm

To the board of directors and shareholders of Statoil ASA

We have audited Statoil ASA's internal control over financial reporting as of 31 December 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Statoil ASA's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on Statoil ASA's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Statoil ASA maintained, in all material respects, effective internal control over financial reporting as of 31 December 2015, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Statoil ASA and subsidiaries as of 31 December 2015 and 2014 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the three-year period ended 31 December 2015, and our report dated 9 March 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG AS

Trondheim, Norway
9 March 2016

9 Terms and definitions

Organisational abbreviations

- ACG - Azeri-Chirag-GunashliX
- ACQ - Annual contract quantity
- AFP - Agreement-based early retirement plan
- AGM - Annual general meeting
- ÅTS - Åsgard transport system
- APA - Awards in pre-defined areas
- ARO - Asset retirement obligation
- BTC - Baku-Tbilisi-Ceyhan pipeline
- CCS - Carbon capture and storage
- CH4 - Methane
- CO_2 - Carbon dioxide
- DKK - Danish Krone
- DPI - Development and Production International
- DPN - Development and Production Norway
- DPUSA - Development and Production USA
- DST - Drill Stem Test
- D&W - Drilling and Well
- EEA - European Economic Area
- EFTA - European Free Trade Association
- EMTN - Euro medium-term note
- EU - European Union
- EU ETS - EU Emissions Trading System
- EUR - Euro
- EXP - Exploration
- FPSO - Floating production, storage and offload vessel
- GAAP - Generally Accepted Accounting Principals
- GBP - British Pound
- GBS - Gravity-based structure
- GDP - Gross domestic product
- GHG - Greenhouse gas
- GSB - Global Strategy and Business Development
- HSE - Health, safety and environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- ICE - Intercontinental Exchange
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- IOR - Improved oil recovery
- LNG - Liquefied natural gas
- LPG - Liquefied petroleum gas
- MMP - Marketing, Midstream and Processing
- MPE - Norwegian Ministry of Petroleum and Energy
- MW - Mega watt
- NCS - Norwegian continental shelf
- NES - New Energy Solutions
- NIOC - National Iranian Oil Company
- NOK - Norwegian kroner
- NOx- Nitrogen oxide
- OECD - Organisation of Economic Co-Operation and Development
- OML - Oil mining lease
- OPEC - Organization of the Petroleum Exporting Countries
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- P5+1 – UN Security Council`s five permanent members
- PDO - Plan for development and operation
- PDQ – Production drilling quarters
- PIO - Plan for installation and operation
- PRD - Project Development organisation
- PSA - Production sharing agreement
- PSR - Procurement and Supplier Relations
- RDI - Research, Development and Innovation

- R&D - Research and development
- ROACE - Return on average capital employed
- RRR - Reserve replacement ratio
- SAGD - Steam-assisted gravity drainage
- SCP - South Caucasus Pipeline System
- SDFI - Norwegian State's Direct Financial Interest
- SEC - Securities and Exchange Commission
- SEK - Swedish Krona
- SFR - Statoil Fuel & Retail
- SIF - Serious Incident Frequency
- TAP - Trans Adriatic Pipeline AG
- TEX - Technology Excellence
- TLP - Tension leg platform
- TPD - Technology, projects and drilling
- TRIF - Total recordable injuries per million hours worked
- TSP - Technical service provider
- UKCS - UK continental shelf
- USD - United States dollar
- WTG - Wind Turbine Generators

Metric abbreviations etc.

- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels of oil equivalent
- mboe - thousand barrels of oil equivalent
- mmboe - million barrels of oil equivalent
- mmcf - million cubic feet
- MMBtu - million british thermal units
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - one thousand million

Equivalent measurements are based upon

- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals 1 standard cubic metre of natural gas
- 1,000 standard cubic meter gas equals 1 standard cubic meter oil equivalent
- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)
- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalent
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms

- Appraisal well: A well drilled to establish the extent and the size of a discovery
- Backwardation and contango are terms used in the crude oil market. Contango is a condition where forward prices exceed spot prices, so the forward curve is upward sloping. Backwardation is the opposite condition, where spot prices exceed forward prices, and the forward curve slopes downward
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material
- BOE (barrels of oil equivalent): A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields
- Downstream: The selling and distribution of products derived from upstream activities
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years
- Heavy oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulphur, nitrogen, and heavy-metal content, as well as higher acid numbers
- High grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritisation and sequencing of drilling targets
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA, which merged with Statoil ASA
- IOR (improved oil recovery): Actual measures resulting in an increased oil recovery factor from a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies
- Liquids: Refers to oil, condensates and NGL
- LNG (liquefied natural gas): Lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG (liquefied petroleum gas): Consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels
- Midstream: Processing, storage, and transport of crude oil, natural gas, natural gas liquids and sulphur
- Naphtha: inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL (natural gas liquids): Light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil
- Oil and gas value chains: Describes the value that is being added at each step from 1) exploring; 2) developing; 3) producing; 4) transportation and refining; and 5) marketing and distribution
- Organic capital expenditures: Capital expenditures excluding acquisitions, capital leases and other investments with significant different cash flow pattern
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas
- Proved reserves: Reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the US Securities and Exchange Commission allows oil companies to report
- Refining reference margin: Is a typical average gross margin of our two refineries, Mongstad and Kalundborg. The reference margin will differ from the actual margin, due to variations in type of crude and other feedstock, throughput, product yields, freight cost, inventory etc
- Rig year: A measure of the number of equivalent rigs operating during a given period. It is calculated as the number of days rigs are operating divided by the number of days in the period
- Upstream: Includes the searching for potential underground or underwater oil and gas fields, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface
- VOC (volatile organic compounds): Organic chemical compounds that have high enough vapour pressures under normal conditions to significantly vaporise and enter the earth's atmosphere (e.g. gasses formed under loading and offloading of crude oil)

10 Forward-looking statements

This Annual Report on Form 20-F contains certain forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Strategy and market overview". In some cases, we use words such as "aim", "ambition", "anticipate", "believe", "continue", "could", "estimate", "expect", "intend", "likely", "objective", "outlook", "may", "plan", "schedule", "seek", "should", "strategy", "target", "will", "goal" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding future financial position, results of operations and cash flows; future financial ratios and information; future financial or operational portfolio or performance; future market position and conditions; future credit rating; business strategy; growth strategy; sales, trading and market strategies; research and development initiatives and strategy; market outlook and future economic projections and assumptions; competitive position; projected regularity and performance levels; expectations related to our recent transactions and projects, such as the sale of interests in the Shah Deniz project and the South Caucasus Pipeline, interests in the Marcellus onshore play in the US, interests in Trans Adriatic Pipeline, interests in Gudrun and acquisition of interests in Eagle Ford in the US, the UK Mariner project, the Peregrino phase II project in Brazil, in addition to the Johan Sverdrup and Aasta Hansteen projects on the NCS, discoveries on the NCS and internationally; our ownership share in Gassled; completion and results of acquisitions, disposals and other contractual arrangements; reserve information; recovery factors and levels; future margins; projected returns; future levels or development of capacity, reserves or resources; future decline of mature fields; planned turnarounds and other maintenance; plans for cessation and decommissioning; oil and gas production forecasts and reporting; growth, expectations and development of production, projects, pipelines or resources; estimates related to production and development levels and dates; operational expectations, estimates, schedules and costs; exploration and development activities, plans and expectations; projections and expectations for upstream and downstream activities; expectations relating to licences; oil, gas, alternative fuel and energy prices and volatility; oil, gas, alternative fuel and energy supply and demand; renewable energy production, industry outlook and carbon capture and storage; organisational structure and policies; planned responses to climate change; technological innovation, implementation, position and expectations; future energy efficiency; projected operational costs or savings; our ability to create or improve value; future sources of financing; exploration and project development expenditure; our goal of safe and efficient operations; effectiveness of our internal policies and plans; our ability to manage our risk exposure; our liquidity levels and management; estimated or future liabilities, obligations or expenses; expected impact of currency and interest rate fluctuations; expectations related to contractual or financial counterparties; capital expenditure estimates and expectations; projected outcome, impact or timing of HSE regulations; HSE goals and objectives of management for future operations; expectations related to regulatory trends; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); projected impact of legal claims against us; plans for capital distribution and amounts of dividends are forward-looking statements. You should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; exchange rate and interest rate fluctuations; the political and economic policies of Norway and other oil-producing countries; EU directives; general economic conditions; political and social stability and economic growth in relevant areas of the world; Euro-zone uncertainty; global political events and actions, including war, terrorism and sanctions; security breaches, including breaches of our digital infrastructure (cybersecurity); changes or uncertainty in or non-compliance with laws and governmental regulations; the timing of bringing new fields on stream; an inability to exploit growth opportunities; material differences from reserves estimates; unsuccessful drilling; an inability to find and develop reserves; ineffectiveness of crisis management systems; adverse changes in tax regimes; the development and use of new technology, particularly in the renewable energy sector; geological or technical difficulties; operational problems; operator error; inadequate insurance coverage; the lack of necessary transportation infrastructure when a field is in a remote location and other transportation problems; the actions of competitors; the actions of field partners; the actions of the Norwegian state as majority shareholder; counterparty defaults; natural disasters, adverse weather conditions, climate change, and other changes to business conditions; failure to meet our ethical and social standards; an inability to attract and retain personnel and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to make them conform to actual results or changes in our expectations.

11 Signature page

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorised the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: /s/ Hans Jakob Hegge
Name: Hans Jakob Hegge
Title: Executive Vice President and Chief Financial Officer

Dated: 18 March 2016

12 Exhibits

The following exhibits are filed as part of this Annual Report:

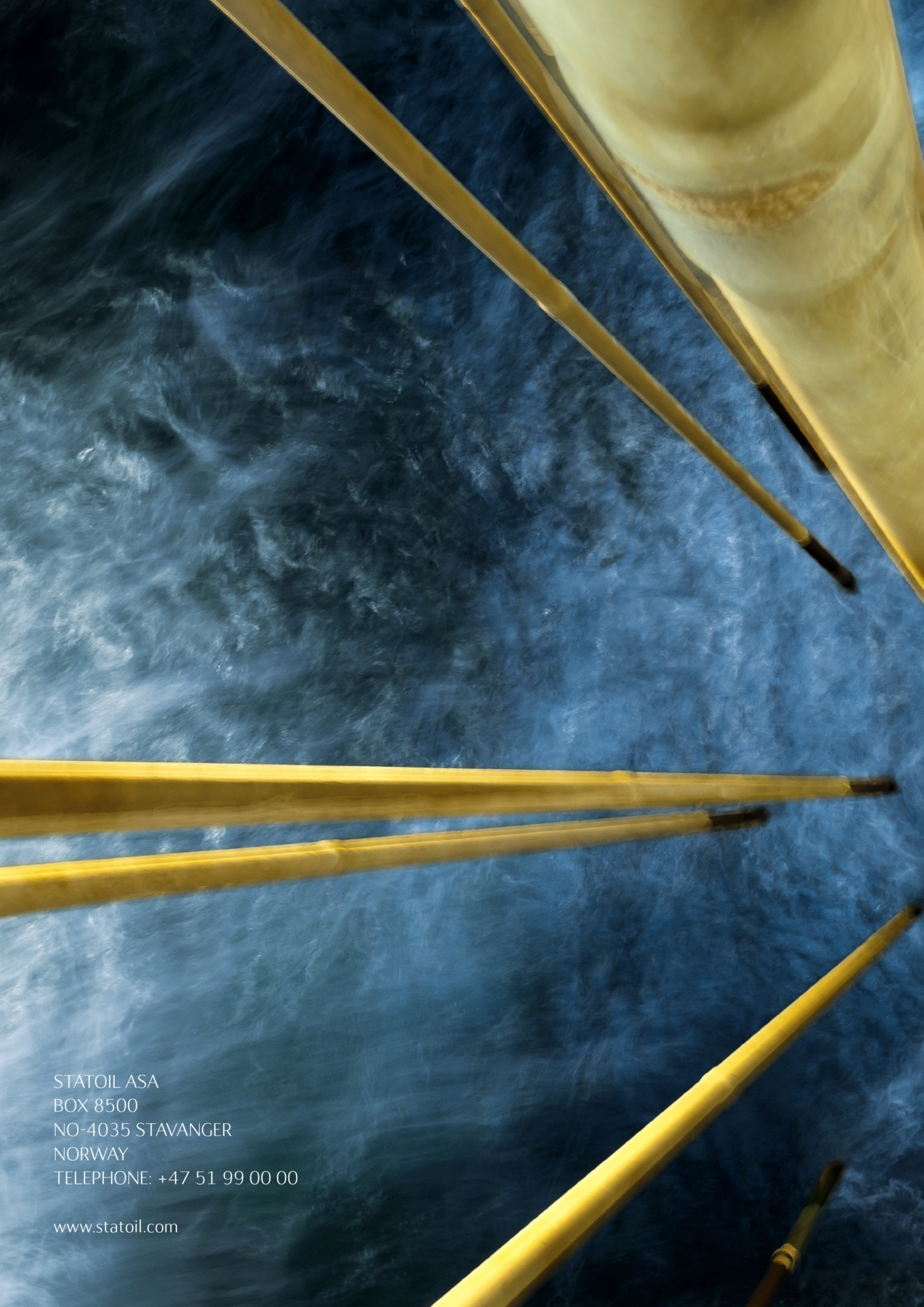
Exhibit no	Description
Exhibit 1	Articles of Association of Statoil ASA, as amended, effective from 14 May 2013 (English translation).
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil Petroleum AS, dated November 24, 2010.
Exhibit 4(c)	Employment agreement with Eldar Sætre as of 4 February 2015.
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see section 3.9 Significant subsidiaries included in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.[1)]
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.[1)]
Exhibit 15(a)(i)	Consent of KPMG AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGoyler and MacNaughton.

1) Furnished only.

The total amount of long-term debt securities of the Registrant and its subsidiaries authorised under any one instrument does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

13 Cross reference to Form 20-F

		Sections
Item 1.	Identity of Directors, Senior Management and Advisers	N/A
Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	1.2; 4.1.2; 6; 6.1.1; 6.7
	B. Capitalisation and Indebtedness	N/A
	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	5.1
Item 4.	Information on the Company	
	A. History and Development of the Company	3.1; 3.2; 4.1.4; 4.1.5; 4.2.3; 8.1.4
	B. Business Overview	2; 3; 4.1.1; 4.1.3
	C. Organisational Structure	3.1; 3.4; 3.9
	D. Property, Plants and Equipment	3.5 - 3.7; 3.13; 4.2.3; 8.1.11; 8.1.22
	Oil and Gas Disclosures	3.10.1; 3.10.2; 3.11; 3.11.1; 3.11.2; 3.11.3; 3.11.4; 8.1.27; Exhibit 15(a)(iv)
Item 4A.	Unresolved Staff Comments	None
Item 5.	Operating and Financial Review and Prospects	
	A. Operating Results	3.12; 4.1; 4.2.4; 5.2.1; 8.1.25
	B. Liquidity and Capital Resources	4.2; 4.2.1; 4.2.2; 4.2.5; 5.2.1; 5.2.2; 8.1.5; 8.1.16; 8.1.18; 8.1.25
	C. Research and development, Patents and Licenses, etc.	3.8.3; 8.1.7
	D. Trend Information	2; 3.3; 3.5.1; 3.5.3; 3.5.4; 3.6; 3.7.1; 3.11; 3.12.5; 4.2; 5; 8.1.23
	E. Off-Balance Sheet Arrangements	4.2.5; 4.2.6; 8.1.22; 8.1.23
	F. Tabular Disclosure of Contractual Obligations	4.2.5
	G. Safe Harbor	10
Item 6.	Directors, Senior Management and Employees	
	A. Directors and Senior Management	7.6; 7.8
	B. Compensation	7.9; 8.1.19
	C. Board Practices	7.5; 7.6; 7.8
	D. Employees	3.16.1; 3.16.3
	E. Share Ownership	6.2.1; 7.6; 7.8; 7.10
Item 7.	Major Shareholders and Related Party Transactions	
	A. Major Shareholders	6.8
	B. Related Party Transactions	3.14; 8.1.24
	C. Interests of Experts and Counsel	N/A
Item 8.	Financial Information	
	A. Consolidated Statements and Other Financial Information	4.1.3; 5.3; 6.1; 8
	B. Significant Changes	8.1.27
Item 9.	The Offer and Listing	
	A. Offer and Listing Details	6.4
	B. Plan of Distribution	N/A
	C. Markets	6; 6.4; 7.7
	D. Selling Shareholders	N/A
	E. Dilution	N/A
	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
	A. Share Capital	N/A
	B. Memorandum and Articles of Association	6.1; 6.8; 7.1; 7.3; 7.10; 8.1.17
	C. Material Contracts	N/A
	D. Exchange Controls	6.6
	E. Taxation	6.5
	F. Dividends and Paying Agents	N/A
	G. Statements by Experts	N/A
	H. Documents On Display	1.1
	I. Subsidiary Information	N/A
Item 11.	Quantitative and Qualitative Disclosures About Market Risk	5; 8.1.5; 8.1.25
Item 12.	Description of Securities Other than Equity Securities	5; 8.1.5; 8.1.25
	A. Debt Securities	N/A
	B. Warrants and Rights	N/A
	C. Other Securities	N/A
	D. American Depositary Shares	6.4.2
Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	None
Item 15.	Controls and Procedures	7.12; 8.2.2
Item 16A.	Audit Committee Financial Expert	7.6.1
Item 16B.	Code of Ethics	7.2
Item 16C.	Principal Accountant Fees and Services	7.1
Item 16D.	Exemptions from the Listing Standards for Audit Committees	7.7
Item 16E.	Purchases of Equity Securities by the Issuer and Affiliated Purchases	6.2
Item 16F.	Changes in Registrant's Certifying Accountant	N/A
Item 16G.	Corporate Governance	7.7
Item 17.	Financial Statements	N/A
Item 18.	Financial Statements	8
Item 19.	Exhibits	12



STATOIL ASA
BOX 8500
NO-4035 STAVANGER
NORWAY
TELEPHONE: +47 51 99 00 00

www.statoil.com