2013

Annual Report on Form 20-F

Statoil

2013

Annual Report on Form 20-F

The Annual Report on Form 20-F is our SEC filing for the fiscal year ended December 31, 2013, as submitted to the US Securities and Exchange Commission.

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Cover photo: Harald Pettersen

2013 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, 2013

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)

Torgrim Reitan
Chief Financial Officer
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Stavanger, Norway
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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 2013 ("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, USA. 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).

The Financial Supervisory Authority (FSA) of Norway has conducted a review of our 2012 financial statements. Statoil has evaluated the impact of the conclusions from the review to be immaterial under IAS 8 for the financial statements for 2013 and prior years. Consequently, no restatement of prior years' comparative amounts has been performed in the 2013 financial statements. See note 28 *Subsequent events* to the Consolidated financial statements for more information.

	For the year ended 31 December				
(in NOK billion, unless stated otherwise)	2013	2012	2011	2010	2009
Financial information					
Total revenues and other income	**637.4**	722.0	670.0	529.9	465.4
Net operating income	**155.5**	206.6	211.8	137.3	121.7
Net income	**39.2**	69.5	78.4	37.6	17.7
Non-current finance debt	**165.5**	101.0	111.6	99.8	96.0
Net interest-bearing debt before adjustments	**58.1**	39.3	71.0	69.5	71.8
Total assets	**885.6**	784.4	768.6	643.3	563.1
Share capital	**8.0**	8.0	8.0	8.0	8.0
Non-controlling interest	**0.5**	0.7	6.2	6.9	1.8
Total equity	**356.0**	319.9	285.2	226.4	200.1
Net debt to capital employed ratio before adjustments	**14.0%**	10.9%	19.9%	23.5%	26.4%
Net debt to capital employed ratio adjusted	**15.2%**	12.4%	21.1%	25.5%	27.6%
Calculated ROACE based on Average Capital Employed before adjustments	**11.3%**	18.7%	22.1%	12.6%	10.6%
Operational information					
Equity oil and gas production (mboe/day)	**1,940**	2,004	1,850	1,888	1,962
Proved oil and gas reserves (mmboe)	**5,600**	5,422	5,426	5,325	5,408
Reserve replacement ratio (three-year average)	**1.1**	1.0	0.9	0.6	0.6
Production cost equity volumes (NOK/boe, last 12 months)	**44**	42	42	38	35
Share information					
Diluted earnings per share NOK	**12.50**	21.60	24.70	11.94	5.74
Share price at Oslo Stock Exchange on 31 December in NOK	**147.00**	139.00	153.50	138.60	144.80
Dividend paid per share NOK (1)	**7.00**	6.75	6.50	6.25	6.00
Dividend paid per share USD (2)	**1.15**	1.21	1.08	1.07	1.04
Weighted average number of ordinary shares outstanding (in thousands)	**3,180,683**	3,181,546	3,182,113	3,182,575	3,183,874

(1) *See Shareholder information* section for a description of how dividends are determined and information on share repurchases. The board of directors will propose the 2013 dividend for approval at the Annual General Meeting scheduled for 14 May 2014.

(2) USD figure presented using the Central Bank of Norway 2013 year-end rate for Norwegian kroner, which was USD 1.00 = 6.08 NOK. The board of directors will propose the 2013 dividend for approval at the Annual General Meeting scheduled for 14 May 2014.

2 Strategy and market overview

The industry is facing demanding challenges and we address these from a position of strength. We have a competitive resource base, a robust financial position and a competent organisation recognised for its technological and operational experience.

Our strategy for value creation and growth remains firm, but we are making some important changes. Stricter project prioritisation and a comprehensive efficiency program will improve cash flow and profitability. Our strong balance sheet enables prioritisation of capital distribution to shareholders.

Statoil expects to invest around USD 20 billion on average per year 2014-16. This will be a reduction of 8% from previous estimates, mainly due to strict prioritisation and increased capital efficiency.

In the 2014-16 period, Statoil expects to maintain return on average capital employed (ROACE) around the 2013 level based on an oil price of USD 100 per barrel (real 2013).

Equity production for 2014 is estimated to grow by around 2% Compound Annual Growth Rate (CAGR) from a 2013 level rebased for divestments and redeterminations.

Statoil will continue to mature the large portfolio of exploration assets and expects to complete around 50 wells in 2014 with a total exploration expenditure level at around USD 3.5 billion, excluding signature bonuses.

Statoil continues to optimise projects in order to increase returns. Our ambition is to continue to keep our unit of production cost in the top quartile of our peer group. Through a comprehensive improvement programme, Statoil expects to realise annual savings of USD 1.3 billion per year from 2016.

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 the section *Forward-Looking Statements* for more information.

2.1 Our business environment

2.1.1 Market overview

The global economy faded further in 2013, the third year of sequentially slower growth. Growth in OECD economies has been low, but improved over the last half year. Non-OECD expansion continues at a relatively solid pace and supports global economic growth and energy demand.

Debt levels and fiscal deficits have come down significantly during 2013 in key OECD economies due to spending cuts, but at the expense of economic growth and employment. Helped by a very expansive monetary policy, growth in advanced economies now seems to be gaining momentum and should strengthen further in 2014. However, high debt, budget cuts and excess capacity will continue to dampen growth in these countries for years to come. Fortunately for global growth and also for global energy demand, growth has persisted in non-OECD economies. They accounted for three-quarters of global growth over the past half-decade. But, a growing number of emerging markets are slowing down. Domestic demand has remained weaker than expected reflecting to varying degrees, tighter financial conditions and policy stances since mid-2013.

The current trends of low growth in the OECD economies and continued development in non-OECD countries are expected to continue, with expected global economic growth of around 3% annually over the next 10 years, comprising 2% annual growth in the OECD economies and 5.2% annual growth in non-OECD economies. This means that the globally weighted, geographical point of economic gravity continues to move gradually eastwards and southwards relative to the OECD economies in Europe and North America.

The growing populations in emerging economies represent a strong long-term driver of economic development and energy demand. Global oil demand grew by 1.2 million barrels per day (mbd) in 2013, as demand in the OECD picked up, supported by rising economic growth. Based on the assumption of steady growth in the Chinese economy, non-OECD oil demand will most likely rise in line with historical trends. Statoil's research suggests that the annual growth in oil demand will average 1.3 mbd over the medium term. A continued positive growth in non-OPEC supply, in particular from North America, tight oil and other liquids, has the potential to increase OPEC spare capacity and weaken fundamentals in global oil markets. The vulnerability of the OECD economies and emerging markets suggests that there is a downside risk to oil prices in the medium term. The elevated supply risk in several producing countries supports a geopolitical risk premium on oil prices.

Due to a general increase in energy demand and the competitiveness of gas in terms of cost and environmental effects, global gas demand is expected to grow. However, the increase in demand will be impacted by energy and climate policies in key regions and countries. Statoil's research suggests that gas demand will increase by 1% and 2% in Europe and in North America, respectively, during the rest of the current decade, whereas Asia will see a growth of 5% in the same period. Both Europe and Asia will have to depend on imports of LNG, which will help sustain a robust price level. In North America, where the revolution in the shale industry has led to increase in proven reserves and production rates have led to historically low prices, prices are expected to gradually increase as the market situation normalises, though the level will remain below that of European and Asian gas prices.

The global economic situation continues to be fragile, with development largely driven by uncertain political environments in key countries and regions, in addition to normal supply and demand factors. Consequently energy prices could vary considerably in the short to medium term.

Production to reserve growth continues to remain a key challenge for international oil companies. Balancing the need for short-term production growth with long-term reserve growth is key to long-term success. We believe Statoil's production development is competitive, especially in combination with our recent exploration results. Increasing competition, tighter fiscal conditions and increasing costs pose challenges when it comes to accessing new profitable resources. It is anticipated that oil companies, including Statoil, will continue to respond to these challenges by adjusting their portfolios in various ways, involving access to unconventional oil and gas assets, increased exploration activities plus cost and portfolio management actions.

Going forward, upward pressure on capital and operational expenditure is expected as companies combat the decline of legacy fields and tackle increasing technical challenges when developing new fields. Companies that are at the forefront of efficient resource management, as well as the effective development and utilisation of new technology, will be best equipped to meet these challenges.

2.1.2 Oil prices and refining margins

The year 2013 saw the price of Brent crude drop 3 USD/bbl from 2012, amid significant volatility. Refinery margins decreased from 2012, falling more steeply since September.

Oil prices

The average price for dated Brent crude in 2013 was USD 108.67/bbl, down USD 3/bbl from 2012. Prices fell from an annual high of USD 119.03/bbl in early February to an annual low of USD 96.83/bbl in April, before rising again to USD 117/bbl in early September. From mid-September, there was less volatility, with prices in a USD 103-113/bbl range. The futures market for Brent at the Intercontinental Exchange (ICE) was generally in backwardation (see section *Terms and definitions*), and particularly so in August/September.

The price of US WTI crude, as quoted at the Cushing tank farm in Oklahoma, averaged USD 98.05/bbl in 2013, up USD 3.90/bbl from 2012. The price fluctuated around USD 95/bbl through June before rising sharply to a USD 105-110/bbl range through most of September. There was then a drop to below USD 95/bbl in November and a rise again later.

Geopolitical factors continued to play a role in 2013. The unrest in Libya started in June, and actual and rumoured production figures subsequently affected prices. In July, the military coup in Egypt raised concerns over the Suez Canal. In late August, the fear that Western involvement in Syria would lead to an all-out Middle East war resulted in an annual price peak. Prices faded as those fears receded.

The price bottomed out in April as refinery maintenance in most regions of the world coincided in that month, leading to very low physical demand. Concerns also surfaced over China, where new policies were seen to affect demand growth. Through the year, a consensus emerged that due to rising North American production, global supply was basically ample. This was seen to limit the price upside to around USD 120/bbl, as there would be no fear of chronic shortages. At the same time, the production cost of the marginal barrel supplied was seen to be around USD 90/bbl, limiting the price downside to that level.

Libya matters a lot to Brent prices, since both Libyan and North Sea volumes are short-haul supply to European refineries. If such scheduled cargoes are cancelled or delayed, refiners have few other alternatives. Due to the backwardation, refiners also do not keep much volume in tanks. The way Brent prices are set, they are particularly affected by the physical balances around UK Forties crude. Due to a trade arrangement with the EU, South Korean refiners are able to lift that crude free of a domestic import tax. Such liftings, plus some production problems at the contributing Buzzard field, helped keep Forties and thereby Brent prices strong with respect to other international crudes, in particular in the fourth quarter.

WTI prices were more affected by internal US logistical factors. Rising shale oil production strained pipeline off-take capacity, and substantial volumes had to be moved by costlier rail freight. Constrained volumes were held up at the Cushing tank farm until July, when new outlets were opened from Cushing to the Gulf Coast. That led to the price rise. However, Gulf Coast refineries are not built to take the light shale oil, and continued production increases led to a new overflow and the price drop to November. Since 1976, the US has enforced a ban on the export of crude oil (except to Canada), and this ban became subject to political debate towards the end of the year.

Refinery margins

Refinery margins in Northwest Europe, as calculated against Brent crude, held up quite well through August. Tightness caused by the heavy maintenance in April was a main driver. In August, the rise in Brent prices was not replicated in prices into Asia, giving Asian refineries a large crude cost advantage. This was used to export substantial volumes of diesel to Europe, using futures contracts at the ICE as a hedge. It also set a ceiling for gasoline prices into export markets. In the fourth quarter, US Gulf Coast refiners saw a similar crude price advantage as WTI prices fell, and also exported diesel to Europe. Under the weight of this, European margins collapsed, and refinery throughput fell. Also noteworthy is that European refiners saw better margins in December from running Russian Urals crude, due to the effect of Forties crude on Brent prices.

As such, the weak refinery margins in the second half of 2013 were mainly seen to be due to a price disadvantage for users of Brent-related crudes. Demand in Europe stabilised at 2012 levels, halting the structural decline seen since 2005.

2.1.3 Natural gas prices

Natural gas prices in Europe were 12% higher on average in 2013 compared with 2012 despite continued weak demand. In North America prices in 2013 averaged 36% higher than in 2012.

Gas prices - Europe

Despite weak demand, European prices were on average 12% higher in 2013 than they were in 2012, averaging $10.3/million british thermal units (MMBtu). This development is best explained by a loss of supply: the import of LNG dropped further as more was sent to higher priced markets in Asia and in South America, and domestic production continued to decline.

Coal and carbon prices weakened further in 2013 as the result of an oversupply in both commodities. This trend, when added to the increase in renewable capacity, led to coal remaining a cheaper option than gas for power generation and to renewables pushing gas generation out of the merit order. Gas-to-power demand therefore decreased by 5.7% year-on-year in 2013 in North West Europe (NWE), while the total demand in the area increased by 1.6% as the result of an extended cold snap in early 2013 and the subsequent requirement to place a larger total volume in storage during the summer. Imports of LNG to Europe fell further by 23%, whereas imports to Asia increased by 7% in 2013. The aftermath of the Fukushima incident continues to impact the global LNG market as the last two remaining reactors in operation were closed down in September. To replace this nuclear power output Japan has had to rely on substitute fuels, in particular LNG. Furthermore, the South Korean nuclear crisis - originating from the discovery of false safety certificates for nuclear parts - also boosted the demand for natural gas.

Gas prices - North America

For most of the year, growth in demand matched supply growth, keeping storage close to normal levels and cash prices in the mid USD 3/MMBtu range. Production growth was the slowest in years, though fast-growing locations like the Marcellus and Eagle Ford shale areas contrasted sharply with declining volumes elsewhere. Cold weather in December meant a shift to a more bullish posture at the close of the year, with prices rising above USD 4/MMBtu. Even though Henry Hub prices varied by over USD 1/MMBtu over the course of the year, price volatility was small by historic standards.

Developments in 2013 may sow the seeds for stronger market prices in the future. On the supply side, the more efficient use of rigs and the absence of a price rally meant that the demand for gas-directed rigs was at a low point in 2013 - the annual average of 384 rigs represented the lowest level for 15 years. On the demand side, gas continues to make gains at coal's expense. Nearly 7 GW of coal-fuelled generators were retired in 2013, due to poor prospects for future use, as natural gas appears to be more competitive than coal in virtually every power market in North America.

North American gas prices are expected to appreciate in coming years, though remaining below Asian and European levels.

2.2 Our corporate strategy

Statoil aims to grow and enhance value through its technology-focused upstream strategy, supplemented by selective positions in the midstream and in low-carbon technologies.

Statoil's top priorities remain to conduct safe, reliable operations with zero harm to people and the environment, and to deliver profitable production growth through disciplined investments and prudent financial management with competitive redistribution of capital to shareholders.

To succeed going forward we continue to focus strategically on the following:

- Sustaining leading exploration company performance
- Take out the full value potential of the Norwegian Continental Shelf (NCS)
- Strengthen global offshore positions
- Maximise the value of our onshore positions
- Creating value from a superior gas position
- Continuing portfolio management to enhance value creation
- Utilising oil and gas expertise and technology to open new renewable energy opportunities

Sustaining leading exploration company performance

We had a successful year of exploration due to our focus on the three exploration strategy pillars:

- **Early access at scale**: We have focused on accessing frontier acreage over the last few years and have been an early mover in several areas. We have accessed significant acreage positions offshore New Zealand and Australia in 2013. We are finalising our JV with Rosneft, accessing both offshore and onshore acreage in Russia.
- **Exploit core positions**: We have secured more acreage in potential clusters such as the US Gulf of Mexico and Brazil. Furthermore, on the NCS, we have maintained high focus on growth and infrastructure lead exploration (ILX) wells with significant potential. Acreage applications in both the 22nd license round and awards in predefined areas (APA) have given Statoil access to promising new high-value prospects on the NCS.
- **Drill significant targets**: We have continued to focus on drilling large targets, leading to several significant discoveries in 2013, including in Canada (Bay du Nord) and in Tanzania (Tangawizi and Mronge).

To replicate our exploration performance, we aim to follow-up on our success in core exploration areas, and balance a continued high activity level with selective access and a focus on efficiency and capital discipline.

Take out the full value potential of the Norwegian Continental Shelf (NCS

The NCS remains a prolific and productive oil and gas province where only half of the resources have been produced.

Over the next ten years, Statoil aims to bring on stream new production from a combination of:

- Developments of larger discoveries, including Aasta Hansteen, Gina Krog and Johan Sverdrup fields, which are expected to contribute considerably to Statoil's total production.
- Developments of a number of smaller discoveries in our fast-track portfolio.
- High activity on improved oil recovery (IOR) projects. Statoil's ambition is to profitably increase oil recovery on the NCS to 60% over time.

Strengthen global offshore positions

Statoil's international oil and gas production has increased from around 100,000 boe to around 720,000 barrels of oil equivalents (boe) per day since the year 2000. Statoil has established a presence in a number of countries and built a strong portfolio of assets outside Norway. To further enhance the materiality of our international portfolio, we are focusing on potential offshore clusters. Clusters are areas that make a material contribution to total production and value creation, where Statoil holds operatorships and has a mix of assets in different stages of development, and where we possess considerable expertise, both below and above ground. Through the cluster focus, our goal is to achieve greater economies of scale, capture synergies and thereby increase profitability.

Our potential clusters are located in some of the most attractive basins in the industry, including:

- **Brazil**; where Peregrino production has reached plateau. In the future, we will focus on further developing the Peregrino area and maturing our exploration portfolio. In 2013, we secured additional exploration acreage through the 11th licensing round.
- **Angola**; where we continue to mature our pre-salt exploration acreage that was awarded in 2011.
- **Tanzania**; which emerged as a new potential cluster in 2012, and where we made two additional significant discoveries. Planning of an LNG plant is being progressed with our partners.
- **East Coast Canada:** emerged as a new potential cluster in 2013 with two discoveries including the significant discovery Bay du Nord. Statoil already has non-operated production in East Coast Canada.

Maximise the value of our onshore positions

Our onshore positions are dominated by our diverse unconventional resources portfolio in North America. It includes operated and non-operated leases in the shale gas and tight oil basins of Marcellus, Eagle Ford and Bakken in the US. In addition, we are maturing our Alberta, Canada Kai Kos Dehseh oil sands project.

Our priorities in the unconventional resources space include:

- Delivering a safe and profitable production ramp up
- Leveraging rapid application of new technology to maximize value creation
- High grading acreage holdings to strengthen current upstream positions
- Demonstrating operational excellence and world class stakeholder management
- Striving for seamless value chain integration and superior price realisation

Creating value from a superior gas position

The dynamics of the gas markets in Europe are changing. There is a development towards a more liberalised market with new players and increased competition. Our gas reserves are located close to the European markets, we have flexible production capabilities and transportation systems, and our commercial experience in gas sales and trading has a proven track record. This puts us in a unique position to take advantage of the evolving European gas markets.

- In the short term, we are making considerable efforts to maximise the value of our gas in this market.
- In the medium to long term, we will continue to promote gas as an important part of meeting European objectives for energy security and emission reductions. We strongly believe that natural gas is the most cost-effective bridge to a low-carbon economy.

Beyond Europe, our planned midstream gas and liquids activities in North America are progressing in step with the building of our upstream unconventional resources business. These activities encompass a mix of capacity commitments, ownership and/or operation of gathering, transportation and storage facilities, marketing alliances and trading operations. They are considered important to meet our goals for flow assurance and margin capture.

Continuing portfolio management to enhance value creation

By being proactive, we intend to further enhance our portfolio in the years ahead, so that it will ultimately be more valuable, more robust and more sustainable beyond 2020. The strategic focus in these endeavours will be to provide financial flexibility, access exploration acreage and unconventional resources, secure operatorships, build cluster positions, manage asset maturity, de-risk positions and demonstrate the intrinsic value of the portfolio. Transactions in 2013 include the NCS asset package sale to OMV and the farm-down of our ownership share in Shah Deniz field in Azerbaijan. These transactions further underpin our ability to release capital for profitable redeployment.

Utilising oil and gas expertise and technology to open new renewable energy opportunities

Growing demand for clean energy is creating new renewable and low-carbon technology business opportunities. Our core capabilities and expertise put us in a position to seize these opportunities in two specific areas: offshore wind and carbon capture and storage (CCS).

In 2013, we saw the first year of commercial operation of the offshore wind-farm Sheringham Shoal in the UK. We continued to mature our Dudgeon wind-farm development offshore UK. In addition, work is continuing on developing the proprietary Hywind floating offshore wind concept. Our ambition is to play an active role in reducing costs and making offshore wind profitable, ultimately without government subsidies or support.

CCS represents a key technology for reducing carbon emissions. We have become a world leader in the development and application of CCS, and we intend to build on our carbon storage experience (the Sleipner, In Salah and Snøhvit projects) to position ourselves for a future commercial CCS business. The large-scale Technology Centre Mongstad testing facility became fully operational in 2013.

2.3 Our technology

We continuously develop and deploy innovative technologies to achieve safe and efficient operations and deliver on our strategic objectives. We have defined four business-critical aspirations that we strive to achieve.

We believe that technology is a critical success factor in the business environment within which we operate. This environment is characterised by an increasingly broad and complex opportunity set, stricter demands on our licence to operate and tougher competition. In this context, technology is increasingly important for resource access and value creation. Our technology development activities aim to reduce field development, drilling and operating costs in order to increase capital efficiency.

Our track record demonstrates our ability to overcome significant technical challenges through the development and deployment of innovative technologies. At present, we believe we are an industry leader in subsurface production and multiphase pipeline transportation.

Our technology strategy, "Putting technology to work", supports our business strategy and strengthens our position as a technology-driven upstream company. It is based on three main principles:

- Prioritising business-critical technologies
- Strengthening our licence to operate
- Expanding our capabilities

Prioritising business-critical technologies

In order to deliver on our strategic objectives for 2020, we strive to meet the following four business-critical technology goals:

- To be an industry leader in seismic imaging and interpretation based on proprietary technology in order to increase our discovery rates
- To achieve breakthrough performance on reservoir characterisation and recovery to maximise value
- A step change in well construction efficiency to drill more cost-effective wells
- To develop and operate "longer, deeper and colder" subsea technologies in order to increase production and recovery and pave the way for Statoil's future "subsea factory"

Strengthening our licence to operate
In order to secure our licence to operate, we must continuously focus on technologies for safe, reliable and efficient operations, as well as supporting integrity management. We are committed to developing and implementing energy-efficient and environmentally sustainable solutions.

Expanding our capabilities
Succeeding in a highly competitive environment will require more than just a strong focus and heavy investments. It will require the ability to build on competitive advantages, stimulate innovation and take a long-term view on selected potentially high-impact technology ventures. To do this, we will:
- Specify asset-specific requirements and execution plans to introduce new solutions
- Provide incentives for and reward those ventures that solve complex technical problems through innovative solutions, particularly when combined with prudent risk management
- Continuously adapt our collaborative way of working with partners and suppliers on a global basis

2.4 Group outlook

Organic capital expenditures for 2014 are estimated at around USD 20 billion. Equity production for 2014 is estimated to grow by around 2% Compound Annual Growth Rate (CAGR) from a 2013 rebased level.

Organic capital expenditures for 2014 (i.e. excluding acquisitions and capital leases), are estimated at around USD 20 billion.

Statoil will continue to mature the large portfolio of exploration assets and expects to complete around 50 wells in 2014 with a total **exploration expenditure** level at around USD 3.5 billion, excluding signature bonuses.

Statoil continues to focus on value creation and **RoACE** is expected to stabilise at the 2013 level, based on an oil price of USD 100 per barrel (real 2013).

Our ambition is to continue to keep our **unit of production cost** in the top quartile of our peer group.

Equity production for 2014 is estimated to grow by around 2% Compound Annual Growth Rate (CAGR) from a 2013 level rebased for divestments and redeterminations.

Scheduled maintenance is estimated to have a negative impact on equity production of around 55 thousand barrels of oil equivalents (mboe) per day for the full year 2014, of which the majority is liquids.

Deferral of gas production to create value, gas off-take, timing of new capacity coming on stream and operational regularity represent the most significant risks related to the production guidance.

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 the section *Forward-Looking Statements* for more information.

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, our 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, we commenced our 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). We 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, we were 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, we have utilised our 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, we carried out an initial public offering of Statoil Fuel & Retail ASA on the Oslo stock exchange (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 sold.

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.

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 headquarter is in Stavanger, Norway. We have business operations in 33 countries and territories and have more than 23,400 employees worldwide.

Statoil is the leading operator on the Norwegian continental shelf (NCS) and is also expanding its international activities. Statoil is present in several of the most important oil and gas provinces in the world. In 2013, 37% of Statoil's equity production came from international activities and the company also holds operatorships internationally.

The company is among the world's largest net sellers of crude oil and condensate, and 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.

In further developing our international business, we intend to utilise our core expertise in areas such as deep waters, heavy oil, harsh environments and gas value chains in order to exploit new opportunities and develop high-quality projects.

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.

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. We believe that we are 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.

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

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 proven 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 North America (DPNA) 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 North America (DPNA)
DPNA comprises our upstream activities in North America. DPNA's ambition is to develop a material and profitable position in North America, including the deepwater regions of the Gulf of Mexico, unconventional oil and gas, and oil sands in the US and Canada. In this connection, we aim to further strengthen our capabilities in deepwater and unconventional oil and gas operations.

Marketing, Processing and Renewable Energy (MPR)
MPR comprises our marketing and trading of oil products and natural gas, transportation, processing and manufacturing, the development of oil and gas value chains, and renewable energy. MPR'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 down costs in the group.

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.

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 DPNA business areas; Marketing, Processing and Renewable Energy (MPR); and Other.

The Other reporting segment includes activities in 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.

On 19 June 2012, Statoil ASA sold its 54% shareholding in Statoil Fuel & Retail ASA (SFR). Up until this transaction SFR was fully consolidated in the Statoil group with a 46% non-controlling interest and reported as a separate reporting segment (FR). The FR segment marketed fuel and related products principally to retail consumers. Following the sale of Statoil Fuel & Retail ASA (SFR), the FR segment ceased to exist.

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.

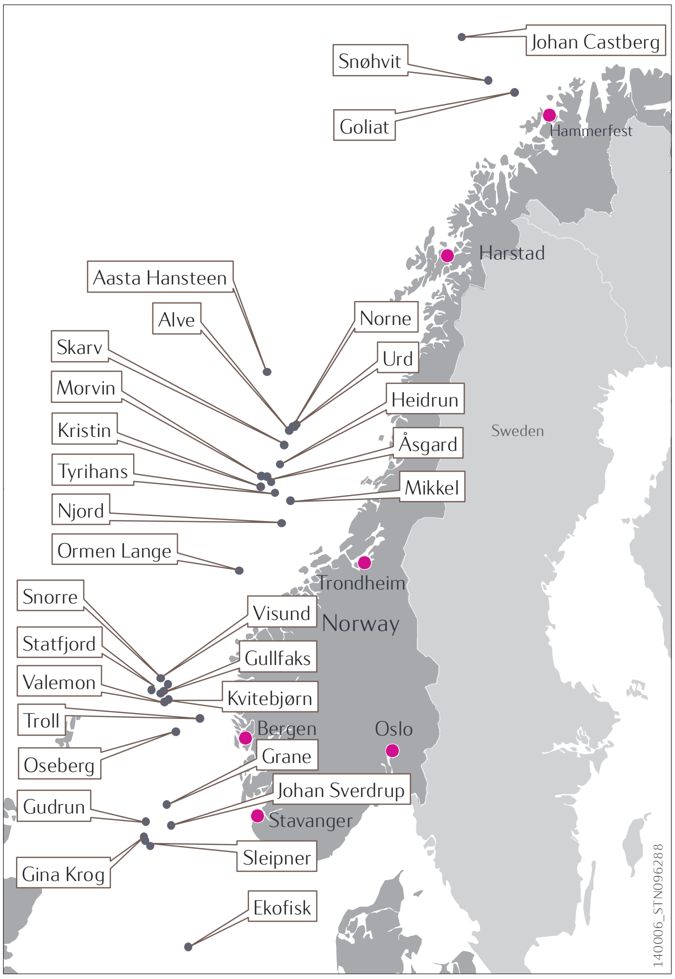
3.5 Development and Production Norway (DPN)

3.5.1 DPN overview

Development and Production Norway (DPN) consists of our exploration, field development and operational activities on the Norwegian continental shelf (NCS).

In 2013 we had 44 Statoil-operated assets in the North Sea, the Norwegian Sea and the Barents Sea, and we also operate a significant number of exploration licences.

Statoil's equity and entitlement production on the NCS was 1,217 mboe per day in 2013. That was about 71% of Statoil's total entitlement production and 63% of Statoil's equity production. In 2013, our daily production of oil and natural gas liquids (NGL) on the NCS was 591 mboe, and our average daily gas production on the NCS was 99 mmcm (4.0 bcf). Acting as operator, Statoil is responsible for approximately 69% of all oil and gas production on the NCS.



DPN has organised the production operations into five business clusters: Operations North, Operations Mid-Norway, Operations North Sea West, Operations North Sea East and Operations South.

1 January 2013, DPN split the former business cluster Operations North into two independent business clusters: Operations North (located in Harstad) and Operations Mid-Norway (located in Stjørdal, near Trondheim). This was a strategically important milestone in relation to expanding our business in the northern region of Norway. The (new) Operations North cluster includes producing assets such as Snøhvit and Norne as well as strategically important fields under development in the Barents Sea. The Operations Mid-Norway business cluster follows up Statoil's activity in the Norwegian Sea as well as fields under development in this region.

The Operations South and Operations North Sea West and East clusters cover our licences in the North Sea. Partner-operated fields cover the entire NCS and are included internally 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. Our efforts in these core areas will also focus on finding and developing smaller fields through the use of existing infrastructure and on increasing production by improving the recovery factor.

We are working to extend production from our existing fields through improved reservoir management and the application of new technology.

Statoil takes an active approach to portfolio management on the NCS. By continuously managing our portfolio, we create value by optimising our positions in core areas and new growth areas in accordance with our strategies and targets.

Key events and portfolio developments in 2013:

- The sales transaction with Wintershall for certain ownership interests in licences on the Norwegian continental shelf (NCS) was closed in the third quarter, and Statoil recognised a gain of NOK 6.4 billion. As part of this agreement, Wintershall took over operatorship of the Brage field on 1 October 2013.
- Statoil signed an agreement with Austrian oil and gas company OMV to divest ownership interests in the Gullfaks and Gudrun fields offshore Norway. The effective date for the transaction was 1 January 2013 with a closing date of 31 October 2013.
- Plan for development and operation (PDO) for the Gina Krog, Aasta Hansteen, Ivar Aasen (partner operated) and Oseberg Delta 2 (fast track project) fields, were approved by the Norwegian Ministry of Petroleum and Energy (MPE).
- Plan for installation and operation (PIO) for the Polarled pipeline was approved by the MPE.
- The investment decision of the Johan Castberg project has been postponed due to uncertainties regarding the resource base and the capex estimates. In addition, the Norwegian government has proposed reduced uplift in the petroleum tax system, which reduces the attractiveness of future projects.
- In October 2013 Statoil, together with the licence partners, decided to mature the concept of a new drilling and processing platform on the Snorre field as part of extending the lifetime of the field to 2040.
- Ormen Lange unit redetermination, reducing ownership share from 28.92% to 25.35%, effective 1 July 2013.
- Production start-up on Skuld, Hyme, Vigdis North-East, Stjerne and Visund North.
- Major oil discoveries in the Grane area in the North Sea, and in the Shetland/Lista formation in the Gullfaks licence.
- Statoil is a partner in the OMV-operated Wisting Central oil discovery in the Hoop area. This represents a new oil play in the Norwegian Barents Sea.
- Eight planned turnarounds were finalised during 2013.
- Several successful appraisal wells were drilled for Johan Sverdrup during 2013. The formal concept selection was made in February 2014. The partners have agreed on a field centre consisting of four installations. The export solutions for oil and gas are based on transport to shore through dedicated pipelines. The oil will be transported to the Mongstad terminal in Hordaland and the gas will be transported via Statpipe to Kårstø in Rogaland. Production start-up is expected at the end of 2019.
- Three appraisal wells were drilled for Johan Castberg during 2013 and a fourth one was started. One well proved an oil discovery, while two proved smaller gas discoveries.
- Statoil was awarded interests in 10 production licences in the Awards in Predefined Areas 2013 (APA 2013) on the Norwegian continental shelf and will be the operator in seven of the licences.

3.5.2 Fields in production on the NCS

In 2013, our total production of entitlement liquids and gas was 1,217 mboe per day, compared to 1,335 mboe per day in 2012.

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 2013, 2012 and 2011. Field areas are groups of fields operated as a single entity.

	For the year ended December 31,								
	2013			2012			2011		
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	24	5	56	22	6	60	30	6	66
Operations Mid	126	15	222	158	17	266	184	18	297
Operations North Sea West	147	16	245	163	16	264	177	15	273
Operations North Sea East	143	32	345	140	39	387	147	25	306
Operations South	94	12	167	93	13	177	112	16	210
Partner Operated Fields	58	20	182	49	21	181	43	19	165
Total	591	99	1,217	624	113	1,335	693	99	1,316

The following table shows the NCS production by fields and field areas in which we were participating as of 31 December 2013. Field areas are groups of fields operated as a single entity.

Business cluster	Geographical area	Statoil's equity interest in %(1)	Operator	On stream	Licence expiry date		Average daily production in 2013 mboe/day
Operations North Sea West							
Kvitebjørn	The North Sea	39.55	Statoil	2004	2031		68.4
Visund	The North Sea	53.20	Statoil	1999	2034		25.7
Gullfaks	The North Sea	51.00	Statoil	1986	2036	(2)	96.0
Gimle	The North Sea	65.13	Statoil	2006	2034	(3)	6.0
Grane	The North Sea	36.66	Statoil	2003	2030		35.6
Veslefrikk	The North Sea	18.00	Statoil	1989	2020	(4)	2.7
Huldra	The North Sea	19.88	Statoil	2001	2015		1.5
Glitne	The North Sea	58.90	Statoil	2001	2013		0.1
Heimdal	The North Sea	29.44	Statoil	1985	2021	(5)	0.0
Brage	The North Sea	0.00	Statoil	1993	2030	(6)	2.6
Volve	The North Sea	59.60	Statoil	2008	2028		6.2
Total Operation North Sea West							244.7
Operations North Sea East							
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030		152.6
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030		38.1
Fram	The North Sea	45.00	Statoil	2003	2024		24.7
Vega Unit	The North Sea	24.00	Statoil	2010	2035	(6)(17)	23.4
Oseberg	The North Sea	49.30	Statoil	1988	2031		101.5
Tune	The North Sea	50.00	Statoil	2002	2032	(7)	4.6
Total Operation North Sea East							344.8
Operations North							
Alve	The Norwegian Sea	85.00	Statoil	2009	2029		7.9
Norne	The Norwegian Sea	39.10	Statoil	1997	2026		6.4
Urd	The Norwegian Sea	63.95	Statoil	2005	2026		10.5
Snøhvit	The Barents Sea	36.79	Statoil	2007	2035		31.5
Total Operations North							56.2
Operations South							
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026		32.5
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026		0.6
Statfjord Øst	The North Sea	31.69	Statoil	1994	2026	(8)	2.1
Sygna	The North Sea	30.71	Statoil	2000	2026	(8)	0.3
Snorre	The North Sea	33.32	Statoil	1992	2015	(9)	29.9
Tordis area	The North Sea	41.50	Statoil	1994	2024		4.1
Vigdis area	The North Sea	41.50	Statoil	1997	2024		14.5
Sleipner Øst	The North Sea	59.60	Statoil	1993	2028		12.6
Sleipner Vest	The North Sea	58.35	Statoil	1996	2028		62.6
Gungne	The North Sea	62.00	Statoil	1996	2028		8.0
Total Operations South							167.2

Business cluster	Geographical area	Statoil's equity interest in %(1)	Operator	On stream	Licence expiry date	Average daily production in 2013 mboe/day
Operations Mid-Norway						
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 (10)	3.5
Hyme	The Norwegian Sea	35.00	Statoil	2013	2014	2.7
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	40.4
Heidrun	The Norwegian Sea	13.04	Statoil	1995	2024 (11)	8.4
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	96.3
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2020 (12)	16.7
Kristin	The Norwegian Sea	55.30	Statoil	2005	2033 (13)	20.6
Morvin	The Norwegian Sea	64.00	Statoil	2010	2027	28.3
Yttergryta	The Norwegian Sea	45.75	Statoil	2009	2027 (14)	5.3
Total Operations Mid-Norway						222.0
Partner Operated Fields						
Skarv	The Norwegian Sea	36.17	BP Norge AS	2013	2033 (15)	36.5
Ormen Lange	The Norwegian Sea	25.35	Shell	2007	2041 (16)	95.4
Vilje	The North Sea	28.85	Marathon Oil	2008	2021	6.6
Gjøa	The North Sea	5.00	GDFSuez	2010	2028 (6)	17.9
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	13.4
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	2.3
Sigyn	The North Sea	60.00	ExxonMobil	2002	2022	7.2
Marulk	The North Sea	50.00	Eni Norge AS	2012	2025	2.9
Total Partner Operated Fields						182.1
Total						1,217.0

(1) Equity interest as of December 31, 2013.

(2) Changed ownership share from 70% to 51% as part of transaction with OMV. Closing date was October 31, 2013.

(3) PL120B expires in 2034 and PL050DS expires in 2023.

(4) PL052 expires in 2020 and PL053 expires in 2031.

(5) PL036 expires in 2021 and PL102 expires in 2025. The ownership share of the topside facilities is 29.44%, however the ownership share of the reservoir and production is 19.87%.

(6) As part of transaction with Wintershall, the ownership share was changed for Brage from 32.7% to 0%, Vega from 54% to 24%, Gjøa from 20% to 5%. Closing date was July 31, 2013.

(7) PL034 expires in 2020, PL053 expires in 2031 and PL190 expires in 2032.

(8) PL037 expires in 2026 and PL089 expires in 2024.

(9) PL089 expires in 2024 and PL057 expires in 2015.

(10) PL107 expires in 2021 and PL132 expires in 2023.

(11) New ownership share 13.04%. Make-up period finished February 28, 2013. PL095 expires in 2024 and PL124 expires in 2025.

(12) PL092 expires in 2020 and PL121 expires in 2022.

(13) PL134B expires in 2027 and PL199 expires in 2033.

(14) PL062 expires in 2027 and PL263C expires in 2037.

(15) PL212/262 expire in 2033 and PL159 expires in 2029.

(16) As part of redetermination the ownership share changed from 28.92% to 25.35% July 1, 2013. Make-up period: July 1, 2013: Dry gas: 19.01%. Sept.1, 2013: Condensate 12.67%.
PL 209/250 expire in 2041 and PL208 expires in 2040.

(17) PL248 expires in 2035 and PL090C expires in 2024.

The following sections provide information about the main producing assets. See the section *Financial review - Operating and financial review - DPN profit and loss analysis* for a discussion of results of operations for 2013, 2012 and 2011.

3.5.2.1 Operations North

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

The region spans from 66 degrees north in the Norwegian Sea to 70 degrees north in the Barents Sea, the latter at the same latitude as the frozen seas in Alaska.

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 (Statoil interest 36.79%) is 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 through a 143-kilometre-long pipeline and then processed at our LNG plant on Melkøya. The LNG was shipped to customers in Europe and Asia in tankers in 2013. 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 suffered from operational challenges in 2013, mainly due to gas leakage in the cold box. The Snøhvit licence has implemented the improvement project "Closing the Gap." The main objectives for the project are a focus on increased production efficiency and plant integrity, improved HSE results, enhanced cost efficiency and intensified expertise throughout the Snøhvit organisation. Snøhvit has produced at 100% capacity and regularity since early July. The main reason for this is that successful modifications have been carried out, such as the removal of inserts from the subcooler and the installation of a new type of molecular sieve mass for gas dehydration. In addition, a daily proactive approach has been implemented to maintain high regularity, especially gas turbine maintenance and the optimal adjustment of the CO_2 content in the feed-gas to match process capacity.

Norne (Statoil interest 39.10%) is an oil field located about 80 kilometres north of Heidrun in the Norwegian sea. The field has been developed using a floating production, storage and offloading vessel (FPSO) connected to subsea templates. Gas is exported through a dedicated pipeline to Åsgard transport and further to Kårstø. Alve, Marulk, Urd and Skuld are tie-in fields connected to Norne FPSO. The Norne FPSO suffered from production problems in 2013 due to a faulty gas export riser. The riser was replaced during the planned turnaround.

Skuld (Statoil interest 63.95%) is a Statoil operated field located outside Norne FPSO and consists of the Fossekall and Dompap reservoirs. The Skuld project is one of the largest fast-track developments and production start-up was March 2013. The field is currently producing from the Fossekall reservoir and production start-up from the Dompap reservoir is planned for 2014.

3.5.2.2 Operations Mid-Norway

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

The region is characterised by petroleum reserves located at water depths of between 250 and 500 metres. The reserves are partly under high pressure and at high temperatures. These conditions have made development and production more difficult, challenging the participants to develop new types of platforms and new technology, such as floating processing systems with subsea production templates.

The **Åsgard** field (Statoil interest 34.57%) development includes the Åsgard A production ship for oil, the Åsgard B semi-submersible floating production platform for gas, and the Åsgard C storage vessel. Gas from the field is piped through the Åsgard Transport System (ÅTS) to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany and from there on to the European gas market. Oil produced at the Åsgard A vessel and condensate from the Åsgard C storage vessel are shipped from the field in shuttle tankers.

Mikkel (Statoil interest 43.97%) is a gas and condensate field. The production is transported to the Åsgard B gas processing platform.

Morvin (Statoil interest 64.00%) is an important contributor to utilising production capacity on Åsgard B. The well stream of oil and gas is tied back to Åsgard B for processing.

Most of the oil from **Heidrun** (Statoil interest 13.04%) is shipped by shuttle tanker to our Mongstad crude oil terminal for onward transportation to customers. Gas from Heidrun provides the feedstock for the methanol plant at Tjeldbergodden in Norway. Additional gas volumes are exported through the Åsgard Transport System (ÅTS) to gas markets in continental Europe.

Kristin (Statoil interest 55.30%) 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. The stabilised condensate is exported to a joint Åsgard and Kristin storage vessel, and the rich gas is transported to shore via the Åsgard Transport System (ÅTS) to the gas processing facility at Kårstø.

Tyrihans (Statoil interest 58.84%) is a subsea development 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.

Njord (Statoil interest 20.00%) is an oil field developed with a semi-submersible drilling and production facility, Njord A. The oil is transported from a storage vessel, Njord B, with shuttle tankers. The gas is transported through the Åsgard Transport System (ÅTS) to Kårstø. The Njord A platform was kept shut down after the 2013 turnaround in September due to structural integrity issues. The structure is currently being reinforced before the temporary resumption of production from Njord and Hyme, planned for the summer of 2014, and estimated to last until the summer of 2015. A Njord Future project has been established with DG1 planned for the summer of 2014.

Hyme (Statoil interest 35.00%) started production in the first quarter of 2013. The field was developed as a fast track Project with a standard subsea template with four well slots. Hyme has one production well and one water injection well, both tied to the Njord facilities. The field is shut down due to work related to Njord structural integrity.

3.5.2.3 Operations North Sea West

Operations North Sea West includes a large part of Statoil's mature production activity on the NCS.

Our main focus is on increasing and prolonging production in the area, giving priority to increased oil recovery, exploration and new field development. The main producing fields in the area are Gullfaks, Kvitebjørn and Grane.

Gullfaks (Statoil interest 51.00%) has been developed with three large concrete production platforms. Oil is stored at Gullfaks A and C before being loaded onto custom-built shuttle tankers on the field. Associated gas is piped to the Kårstø gas processing plant and then on to continental Europe. 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.

Both oil and gas production was somewhat higher than expected in 2013. This is due to improved reservoir response and new water injection in the main field, successful delivery of many new satellite wells, and good production from the new Shetland/Lista discovery announced in April. Drilling activities have been very high. The first new water injector on the main field has been delivered, and all three fixed installations are currently drilling new wells. Operations here also include delineation activities of the Shetland/Lista discovery. On the satellites, two mobile rigs have been delivering new wells at a high rate contributing strongly to the production. Currently, drilling of the new Gullfaks South Increased Oil Recovery (GSO IOR) project wells is ongoing. Operations on the satellites will continue with two mobile rigs in 2014.

Replacing of the offshore loading buoys was approved late in 2012. Two other large projects are planned to be developed: Gullfaks Rimfaksdalen and Gullfaks Modular drilling rig. The projects Gullfaks C Subsea compressor and Gullfaks South IOR have started offshore mobilisation for topside work. Two new templates have been installed by GSO project. Upgrade of the water injection capacity at Gullfaks B was completed in February 2014.

High activity level will continue at Gullfaks B and C and the activity level at Gullfaks A will increase in 2014. Turnarounds are planned at Gullfaks A and B in May/June 2014.

Gullfaks was one of the assets included in the transaction with Austrian oil and gas company OMV. As a result of this agreement Statoil reduced its ownership share in Gullfaks from 70% to 51%. In addition to the cash consideration of USD 2.65 billion, the transaction with OMV included a contingent payment related to the Shetland Lista discovery on Gullfaks.

Kvitebjørn (Statoil interest 39.55%) is a gas and condensate field, where gas and condensate from the Kvitebjørn platform are transported through pipelines to Kollsnes and Mongstad, respectively. The Kvitebjørn platform processing facilities will be expanded by a compressor module, and re-compression of the gas is expected to increase the expected production of gas and condensate, thereby increasing the recovery rate from the reservoir. Offshore installation of the compressor module is assumed to take place in 2013 and 2014, with assumed start-up of the module in the third quarter of 2014.

Grane (Statoil interest 36.66%) is Statoil's largest producing heavy oil field. Oil from Grane is piped to the Sture terminal, where it is stored and shipped. In 2014 the plan is to re-open gas import for injection in the reservoir with the aim of reducing pressure decline.

Visund (Statoil interest 53.20%) is an oil and gas field development that includes a floating drilling, production and living quarter unit and two subsea templates, in the northern and southern parts of the field. Production from the Visund South template started in the fourth quarter of 2012 and production from the Visund North template started in the fourth quarter of 2013.

Heimdal (Statoil interest 29.44%). The Heimdal platforms are preparing for the reception of rich gas from the Valemon field in the fourth quarter of 2014, and are therefore upgraded for another 20 years' lifetime extension. In parallel, a modular drilling rig is under construction in order to plug and abandon all 12 wells at the Heimdal main reservoir. The old drilling rig was successfully removed in August 2013. The basis for lifetime extension of the Heimdal-Brae Alpha 8" subsea condensate pipeline was successfully concluded in September 2013.

Volve (Statoil interest 59.60 %). Volve has executed a drilling programme in 2013. The drilling of well F11-A, and a successful exploration pilot at Volve North West, have increased the proved reserves. As a result the field life has been extended by two years, and production is now expected to run to the third quarter of 2016.

Veslefrikk (Statoil interest 18.00 %). Veslefrikk has finished the drilling upgrade project in 2013. The main strategy for Veslefrikk is to re-establish the reservoir pressure by water injection as well as the drilling of new wells to increase the oil and gas production for the coming years.

Huldra (Statoil interest 19.90 %). The strategy is to produce maximum of gas and condensate before permanent shutdown in April 2014, when the Huldrapipe will be handed over to the Valemon Project for tie-in of the Valemon pipe to Heimdal. Permanent plug and abandonment of the Huldra wells is expected to be carried out in 2016, and the plan is that the Huldra topside facilities will be removed in 2017.

Glitne (Statoil interest 58.90%). Glitne ceased production in February 2013 and decommissioning of the field has commenced.

3.5.2.4 Operations North Sea East

Operations North Sea East is a major gas area that also contains significant quantities of oil.

The main producing fields in the area are Troll and Oseberg. These fields are among the largest producing fields on the Norwegian continental shelf (NCS).

In 2013 the plan for the development and operation (PDO) of Oseberg Delta 2 was approved. The Oseberg Delta 2 development concept is a subsea tie-back to Oseberg Field Centre through the existing Delta S1 subsea infrastructure.

As part of the transaction with Wintershall, a farm-down in Vega has been completed. Statoil's interest in Vega (PL090C, PL248 and PL248B) has decreased from 54% to 24%.

Troll (Statoil interest 30.58%) 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.

In 2013, Troll experienced some operational difficulties with one of the two electric motors driving Troll A export compressors. Production has been maintained at the expected level using one compressor in 2013. A permanent replacement of the engine is planned in the third quarter of 2014.

The **Oseberg area** (Statoil interest 49.30%) includes the Oseberg Field Centre, Oseberg C, Oseberg East and Oseberg South production platforms. Oil and gas from the satellites are piped to the Oseberg Field Centre for processing and transportation. Oil is exported to shore through the Oseberg transportation system to the Sture Terminal, and gas is exported through the Oseberg gas transportation system to Heimdal and from there to the market.

3.5.2.5 Operations South

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

Operations South also produces from the satellite fields Tordis and Vigdis, which are tied into Gullfaks C and Snorre A, as well as Statfjord satellites, which are tied into the Statfjord C platform.

Sleipner consists of the Sleipner East (Statoil interest 59.60%), Gungne (Statoil interest 62.00%) and Sleipner West (Statoil interest 58.35%) gas and condensate fields. The gas from Sleipner has a high level of carbon dioxide. It is extracted on the field and re-injected into a sand layer beneath the seabed to reduce carbon dioxide emissions to the air. The Gudrun and Gina Krog fields, which are under development, will be tied into Sleipner.

The **Snorre** field (Statoil interest 33.32%) development involves two floating platforms and one subsea production system connected to one of the platforms (Snorre A). Oil and gas from the Snorre field are exported to Statfjord for final processing, storage and loading.

Statfjord (Statoil interest 44.34%) has been developed using three fully integrated platforms supported by gravity-based structures with concrete storage cells and an offshore loading system. The Statfjord A lifetime has recently been extended from 2016 to 2020, while Statfjord B and Statfjord C will continue production to 2025. The Statfjord Late Life Project was completed in 2012 to enable a drainage strategy that will produce remaining gas reserves through water production/pressure depletion.

The **Statfjord satellites** consist of Statfjord North (Statoil interest 21.88%), Statfjord East (Statoil interest 31.69%) and Sygna (Statoil interest 30.71%). These satellites, which have all been developed using subsea templates tied back to Statfjord C, are expected to produce until 2025.

3.5.2.6 Partner-operated fields

Partner-operated fields account for approximately 15% of our total oil and gas production on the NCS. The main producing fields are Ormen Lange, Skarv, Ekofisk and Gjøa.

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

Ormen Lange (Statoil interest 25.35%), 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. The gas is then transported through a dry gas pipeline, Langeled, via Sleipner to Easington in the UK. Statoil's equity share has been adjusted from 28.92% to 25.35% as a consequence of the recent redetermination process in the Ormen Lange Unit, effective from 1 July 2013.

Skarv (Statoil interest 36.17%) 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. Oil is exported by offshore loading, and gas is exported via the Åsgard Transport System (ÅTS). The field was put into production 31 December 2012. All wells were drilled and had come on stream by November 2013. Skarv is still ramping up and optimising production.

Ekofisk is operated by ConocoPhillips. It consists of the Ekofisk, Eldfisk and Embla fields (Statoil interest 7.60%), and Tor (Statoil interest 6.64%). Investment decisions were made in 2010 for a new Ekofisk South project (production started at the end of October 2013) consisting of a new drilling platform with subsea water injection facilities and the redevelopment of Eldfisk. The projects are progressing according to plan and are expected to extend the field life considerably beyond the current licence period, which ends in 2028.

Gjøa (Statoil interest 5.00%) is operated by GDF SUEZ. Gjøa has been developed using a subsea production system and a semi-submersible production platform. Gas is exported via the Far North Liquids and Associated Gas System (FLAGS) pipeline to St Fergus, and oil is exported via the Troll 2 pipeline to the Statoil-operated Mongstad refinery near Bergen. The platform is supplied with land-based electricity from Mongstad. On 22 October 2012, Statoil entered into an agreement with Wintershall, including a farm down in the Gjøa licence from 20% to 5% effective from 1 January 2013. The transaction was closed 31 July 2013.

3.5.3 Exploration on the NCS

Statoil continues to exploit its core position on the NCS with successful exploration results in 2013.

The successful exploration results in 2013 were characterised by new discoveries in the North Sea, the Norwegian Sea and the Barents Sea and by appraisal activity in the Johan Sverdrup field. It reflects the diversified exploration portfolio on the NCS, which includes targeting growth prospects, new opportunities in frontier areas, as well as selected prospects in mature areas that can be tied into existing infrastructure.

Furthermore, Statoil was awarded interests in seven production licences in the Barents Sea in the 22nd licensing round on the Norwegian continental shelf (NCS), of which three licences will be Statoil operated. Additional interests in 14 production licences were awarded in the APA round, of which seven are operated by Statoil.

The table below shows the exploration and development wells drilled on the NCS in the last three years. The number significantly increased from 19 exploration wells completed in 2012 to 35 exploration wells completed in 2013.

	2013	2012	2011
North Sea			
Statoil operated exploratory	11	7	13
Statoil operated development	85	59	61
Partner operated exploratory	10	7	6
Partner operated development	20	12	12
Norwegian Sea			
Statoil operated exploratory	7	1	2
Statoil operated development	19	18	14
Partner operated exploratory	1	2	0
Partner operated development	3	7	6
Barents Sea			
Statoil operated exploratory	2	2	2
Statoil operated development	0	0	0
Partner operated exploratory	4	0	1
Partner operated development	3	0	0
Totals			
Exploratory	35	19	24
Exploration extensions wells	7	1	4
Development wells	130	96	93

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 2012	Number of licenses (NCS Total)	Number of licenses (Statoil equity)	Number of licenses (Statoil Op.)	New licenses (Statoil equity)	New licenses (Statoil Op.)
NCS total	148,258	48,224	7,215	515	238	170	25	14
North Sea	55,291	15,265	(1,162)	305	130	100	13	9
Norwegian Sea	53,063	16,346	1,262	143	71	48	2	2
Barents Sea	39,904	16,613	7,115	67	37	22	10	4

North Sea

In the North Sea, Statoil participated in 21 completed exploration wells and seven exploration extension wells. Statoil operated 10 of the exploration wells. Five of the Statoil-operated wells (namely Grane F, Askja West, and three Johan Sverdrup appraisal wells) and six of the partner-operated wells were announced as discoveries. The main activity in this area was the appraisal of the Johan Sverdrup discovery. In 2014/2015 Statoil plans to further drill in the King Lear area in order to clarify the remaining potential. We will also pursue our exploration efforts around existing infrastructure in order to discover timely high-value barrels for the new fast-track developments and will work on maturing new opportunities in the Utsira High area.

Norwegian Sea

Exploration activity in the Norwegian Sea increased significantly in 2013 compared to previous years and was rather successful with three encouraging discoveries (Smørbukk North, Svale North and Snilehorn), which are all potential tie-ins to existing fields and which thus prove the remaining potential of the NCS. All of those discoveries were Statoil operated and Snilehorn was the last Statoil operated well in the current exploration campaign in the Norwegian Sea. A total of eight wells were drilled in the Norwegian Sea, of which Statoil operated seven. Statoil does not plan any operated wells in the Norwegian Sea in 2014, but will focus on preparing for the deepwater exploration campaign in the Aasta Hansteen area, which is scheduled to start in 2015.

Barents Sea

Six wells were completed in the Barents Sea in 2013, with Statoil operating three of them. In total, four discoveries were announced (Norvarg, Wisting Central, Iskrystall and Skavl), with Wisting Central being the first well in the frontier Hoop area, which represents a new oil play in the region. The Barents Sea contains the largest unexplored acreage on the NCS, with substantial exploration potential both in presently opened and unopened areas. Statoil will therefore continue its exploration campaign in the Barents Sea in 2014 with continued exploration drilling around the Johan Castberg discoveries, as well as in the Hoop area.

Another important focus area will be related to the 23rd licensing round. Statoil delivered its nomination for the 23rd round to the Norwegian authorities at the beginning of January 2014. Statoil is also operator of the industry project for joint 3D seismic acquisition in the south-eastern Barents Sea.

3.5.4 Fields under development on the NCS

A number of fields are currently under development on the NCS, including traditional, fast-track and redevelopment projects.

The table below shows some key figures as of 31 December 2013 for our major development projects on the NCS.

Project	Operator	Statoil's share at 31 december 2013	Production start	Statoil equity capacity (mboe per day)
Aasta Hansteen	Statoil	75.00	2017	100
Gudrun	Statoil	51.00	2014	65
Valemon	Statoil	53.78	2014	50
Gina Krog	Statoil	58.46	2017	50
Ivar Aasen	Det Norske	50.00	2016	40
Goliat	Eni	35.00	2014	30
Edvard Grieg	Lundin	15.00	2015	14

Aasta Hansteen (Statoil interest 75.00%) is a deepwater 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. The total investments are estimated to amount to NOK 36.7 billion. Expected production start-up is in 2017.

The **Gudrun** (Statoil interest 51.00%) oil and gas field is located in the North Sea. During 2013, Statoil sold 24% of its interest share in the field to OMV, effective from 1 Nov 2013, thus reducing the interest share from 75% to 51%. Production is scheduled to start in the first quarter of 2014. The total investments are estimated to amount to NOK 23.7 billion. The field development includes a separate steel jacket-based process platform for separation of the oil and gas. Gas and partly stabilised oil will be transported in separate pipelines from Gudrun to Sleipner. Production drilling started in September 2011. It is being performed by the jack-up rig *West Epsilon*. One production well will be drilled and completed prior to production start-up. By the end of 2014, four wells are scheduled to be in production.

Valemon (Statoil interest 53.78%), which is located in the North Sea, is being developed using a steel jacket platform with gas, condensate and water separation. Production drilling started in the third quarter of 2012, and it is being performed using the jack-up rig *West Elara*. The field development costs are estimated to be NOK 22 billion, and production start-up is expected late 2014.

Gina Krog (formerly Dagny) (Statoil interest 58.46%) 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. Development also includes gas injection in order to maximise the recovery factor for the field. The development concept includes a total of 15 wells. Total investments are estimated to amount to NOK 34.8 billion. Expected production start-up is in 2017.

Ivar Aasen is an oil and gas field located in the Utsira High Area. Its 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, and Statoil holds an interest of 50%. 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, and Statoil holds an interest of 35%.

Edvard Grieg is an oil field located in the Utsira High Area. Its development will include a fixed steel jacket with processing and export facilities. Edvard Grieg is operated by Lundin and Statoil holds a 15% interest in the field. The operator expects production start-up in the fourth quarter of 2015. Statoil entered into an agreement with Wintershall, including acquisition of shares in the Edvard Grieg licence. The transaction was closed 31 July 2013.

Fast-track projects are all relatively small projects, yielding high returns. This initiative was taken in order to address time criticality and cost challenge issues relating to Statoil's portfolio of smaller discoveries and prospects close to existing infrastructure. By rationalising the time and resources used, improving collaboration and deploying standard equipment, the goal is to shorten the normal period between discovery and production to only 2.5 years and to reduce costs by 30%. In Statoil's opinion, the initiative has led to cost-efficient development solutions for this kind of discovery. The main challenge experienced in the execution phase has been the timely availability of rigs for production drilling.

Statoil's fast-track project development initiative is progressing well. As of 31 December 2013, eleven projects have been sanctioned, of which six have started production in 2012 and 2013, while five are scheduled to start production during 2014. In addition, several other smaller discovery candidates are being considered for fast-track development.

Redevelopment on the NCS - Improved oil recovery (IOR)
The main purpose of maturing IOR projects is to extend the lifetime of existing installations, increase oil recovery and exploit new profitable opportunities. Statoil has set a very ambitious target of increasing the average recovery rate from our oil fields on the NCS from 50% to an estimated 60% by 2020.

There is therefore intense activity directed at maturing IOR projects on the NCS, and the following projects are some of the largest currently being developed:

The **Gullfaks B water injection upgrade** project includes the replacement of the pipeline from Gullfaks A to Gullfaks B, an upgrade of the existing water injection system, and increased water injection capacity on Gullfaks B. The project was completed in January 2014.

The main purpose of the **Kvitebjørn pre-compression project** is to increase and accelerate gas and condensate recovery by facilitating low-pressure production. Start-up is scheduled for June 2014.

Kristin low-pressure production is an IOR project that aims to increase production from the Kristin and Tyrihans fields on Haltenbanken by installing a new low-pressure compressor on the Kristin platform. The expected date of completion is mid-2014.

The **Troll A third and fourth pre-compressor project** is 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 investment costs are estimated at NOK 10.3 billion and the expected completion date is the fourth quarter of 2015.

Subsea compression innovation and technology development are essential to improved oil and gas recovery and to extending the life of the fields on the NCS. The development of subsea compression and processing is a central part of Statoil's technology strategy for long-term production growth. Subsea gas compression is an important step on the road towards our ambition of installing the elements for a "subsea factory". Subsea processing is key to gaining access to resources in Arctic areas and deepwater assets.

Åsgard subsea compression is one of Statoil's most demanding technology projects aimed at improved recovery. The project will install compact subsea compressors in the Midgard part of the Åsgard fields. The purpose of the project is to increase the recoverable reserves significantly by introducing innovative subsea compression of the well stream. The investment cost for the project is estimated to be NOK 17 billion and completion of the development is currently expected to take place in 2015.

Gullfaks subsea compression is the second largest subsea gas compression project planned by Statoil on the NCS. Subsea gas compression will have a great effect on the Gullfaks field as this technology, combined with conventional low-pressure production, will help increase the recovery rate from the Gullfaks South Brent reservoir from 62% to 74%. This project is scheduled for completion in 2015.

3.5.5 Decommissioning on the NCS

The decommissioning of the Glitne field commenced in 2013

The Norwegian government has laid down strict procedures for the removal and disposal of offshore oil and gas installations in the Petroleum Act. 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 during 2013. Permanent plugging and abandonment of the seven wells is planned to start in 2014. Glitne commenced production in 2001 as a marginal field and achieved a production that was double the original reserve estimate.

Huldra is planning to cease production during 2014, after 13 years in production. Permanent plugging and abandonment of six wells is planned for 2016-2017. Removal work will start in 2017.

Yttergryta is a subsea field with one production well that ceased production in 2013. Permanent plugging of the well is planned for 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, and DPI is expected to account for a larger share of Statoil's production in the future.

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

On 16 January 2013, Statoil, together with partners BP and Sonatrach, were hit by a terrorist attack at the In Amenas gas production facility. The attack caused the death of 40 workers at the facility, of which 5 were Statoil colleagues. In February 2013, the Board appointed an independent investigation team to clarify and evaluate the facts related to the attack, and to provide the company with a basis for making further improvements to its security, risk assessment and emergency preparedness. On 12 September 2013 the independent investigation team presented their report. The report points to areas within our security system that require improvement and an increased focus. A Security Improvement Programme has therefore been established to develop a robust and coherent security culture in the company, and to make sure that the 19 recommendations from the report are prioritised and integrated in the company security work.

In 2013, the reporting segment was engaged in production in 11 countries: Algeria, Angola, Azerbaijan, Brazil, Canada, Libya, Nigeria, Russia, the UK, the US, and Venezuela. In 2013, DPI produced 37% of Statoil's total equity production of oil and gas.

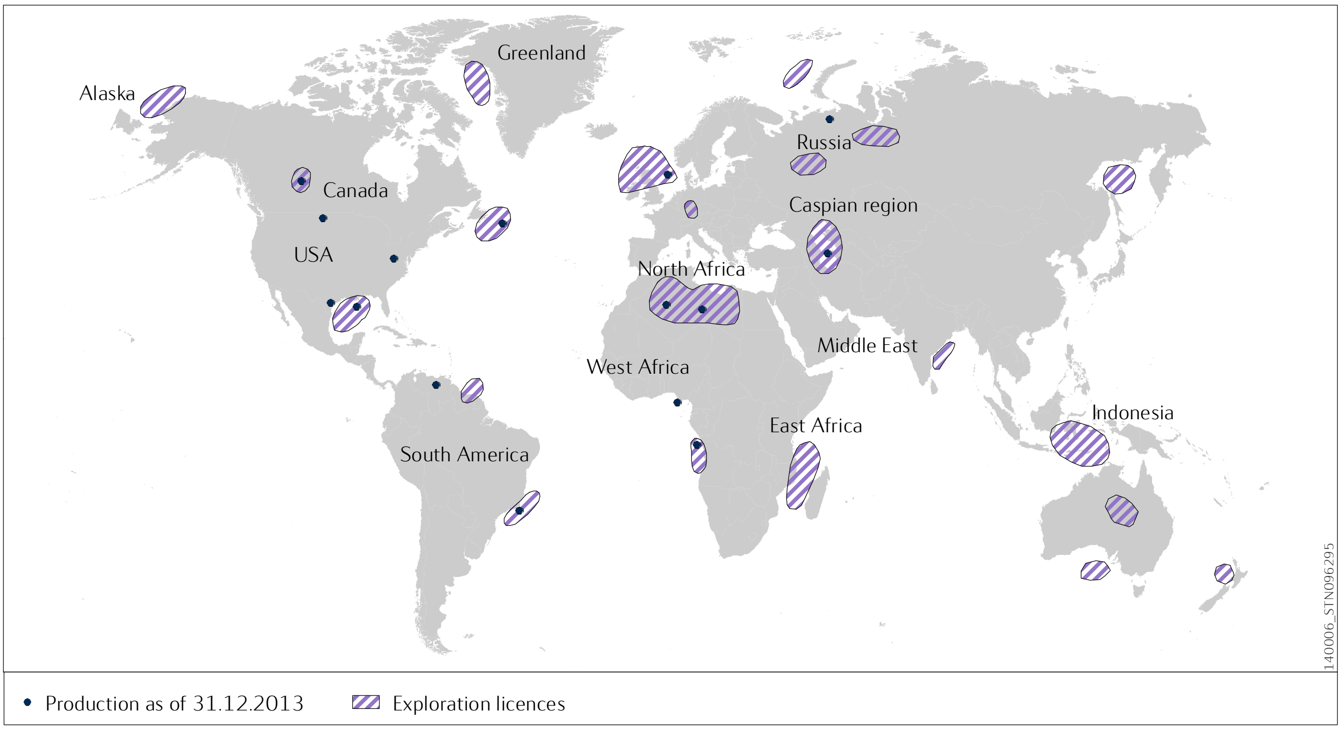
On 1 August 2013, Statoil closed its office in Tehran, Iran. In 2012, Statoil completed cost recovery for previous investments. Statoil still has some minor remaining payment obligations for tax and social security under legacy contracts. These will be dealt with in accordance with all applicable sanctions.

As of 31 December 2013, Statoil has exploration licences in North America (Alaska, Canada, and the Gulf of Mexico), South America and sub-Saharan Africa (Angola, Brazil, Mozambique, Suriname, and Tanzania), the Middle East and North Africa (Azerbaijan and Libya), Europe and Asia (the Faroe Islands, Germany, Greenland, India, Indonesia, Russia and the UK) as well as Oceania (Australia and New Zealand).

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

The main sanctioned development projects in which DPI is involved are in Angola, Azerbaijan, Canada, the UK, and the US.

The map shows Statoil's international exploration and production areas.



Key events and portfolio developments in 2013:

- Equity production increased by 8% from 2012, to 723 mboe per day in 2013:
  - Marcellus shale investment grew production by 40 mboe per day in 2013
  - PSVM in Angola started production in December 2012 and has during 2013 been ramping up.

- In February 2013, the UK government's Department of Energy and Climate Change (DECC) announced their approval of the field development plan for the Mariner heavy oil field.
- The company had two additional natural gas discoveries off the coasts of Tanzania (Tangawizi-1 and Mronge-1) in March 2013 and December 2013 respectively.
- Julia field in Gulf of Mexico operated by Exxon Mobil was sanctioned in April 2013 by Statoil and its partners.
- In April 2013, Statoil and its partners sanctioned Heidelberg field in Gulf of Mexico.
- New acreage was secured globally through farm-in agreements in Australia (four offshore as well as four onshore licences) in May 2013, Brazil (six licences in the Espirito Santo basin during the 11th licensing round) also in May, Gulf of Mexico (17 leases in the Central and Western lease sales), UK (interest in seven exploration licences in the UK 27th licensing round in November 2013) and New Zealand (100% equity share in an exploration permit in the Reinga-Northland Offshore Release Area in the New Zealand Block Offer December 2013).
- Statoil recorded two oil discoveries in Canada (Harpoon and Bay du Nord) in June and August 2013 respectively.
- Statoil signed agreements with Rosneft that completed the contractual framework of a joint venture to explore offshore frontier areas in the Sea of Okhotsk and the Barents Sea in June. We also signed a Shareholders and Operating Agreements (SOA) to explore shale oil opportunities in the Samara region.
- Statoil assumed operatorship of it 50% share of its Eagle Ford JV interest with Talisman in July 2013.
- In October 2013, Statoil closed the sale with the Austrian oil and gas company OMV to exit Schiehallion and Rosebank fields West of Shetlands. See section *Business overview - Development and Production Norway (DPN) - DPN overview* for more details about the sales transaction with OMV.
- In December 2013, Statoil and its partners in the Shah Deniz consortium made the final investment decision for the development of the Stage 2 development of the Shah Deniz gas field in Azerbaijan and expansion of the South Caucasus Pipeline (SCPX) through Azerbaijan and Georgia. Before this, in second quarter, the Shah Deniz consortium announced that it had selected Trans Adriatic Pipeline (TAP) to transport gas across Greece, Albania and into Italy.
- In December 2013, Statoil signed an agreement to divest a 10% share of its 25.5% holdings in Shah Deniz and the South Caucasus Pipeline. The effective date of the transaction is 1 January 2014. The divestment is pending government approval and other conditions.
- In January 2014, Statoil and its partner, PTTEP in the Kai Kos Dehseh (KKD) oil sands project in Alberta, Canada, announced an agreement to divide their respective interests in the KKD oil sands project with an effective date 1 January 2013, with closing expected by the third quarter of 2014.

3.6.2 International production

Statoil's entitlement production outside Norway was about 29% of Statoil's total entitlement production in 2013.

The following table shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2013, 2012 and 2011. Entitlement production figures are after deductions for royalties paid in kind, production sharing and profit sharing. As of fourth quarter 2013, entitlement production from the upstream segment in the US is presented net of royalties. Going forward, this will be the presentation format applied. Historical U.S. entitlement volumes have been adjusted for comparability to current year presentation.

	For the year ended 31 December		
Entitlement production	2013	2012	2011
Oil and NGL (mboe per day)	373	342	252
Natural gas (mmcm per day)	26	20	13
Total (mboe per day)	539	470	334
Total - net of US royalties (mboe per day)	502	443	327

The table below provides information about the fields that contributed to production in 2013.

Producing fields during calendar year 2013

Field	Statoil's equity interest in per cent	Operator	On stream	License expiry	Average daily equity production mboe/d	Average daily entitlement production [1] mboe/day
North America					225.7	188.4
Canada: Hibernia	5.00%	HMDC	1997	2027	6.9	6.9
Canada: Terra Nova	15.00%	Suncor	2002	2022	5.7	5.7
Canada: Leismer Demo	60.00%	Statoil	2010	HBP [2]	8.9	8.9
USA: Spiderman	18.33%	Anadarko	2007	HBP	1.3	1.1
USA: Zia	35.00%	Devon	2003	HBP	0.0	0.0
USA: Marcellus [3]	Varies	Chesapeake/Statoil	2008	HBP	101.8	85.6
USA: Eagle Ford [3]	Varies	Talisman/Statoil	2010	HBP	27.7	20.2
USA: Tahiti	25.00%	Chevron	2009	HBP	19.1	15.7
USA: Bakken [3]	Varies	Statoil/others	2011	HBP	47.4	37.8
USA: Caesar-Tonga	23.55%	Anadarko	2012	HBP	6.9	6.5
South America					54.3	54.3
Brazil: Peregrino	60.00%	Statoil	2011	2034	43.1	43.1
Venezuela: Petrocedeño [4]	9.68%	Petrocedeño	2008	2032	11.2	11.2
Sub-Saharan Africa					250.5	148.7
Angola: Block 4/05, Gimboa	20.00%	Sonangol P&P	2009	2026	2.0	1.8
Angola, Block 15: Kizomba A	13.33%	ExxonMobil	2004	2026	13.1	4.2
Angola, Block 15: Kizomba B	13.33%	ExxonMobil	2005	2027	13.0	4.7
Angola, Block 15: Kizomba Satellites phase 1	13.33%	ExxonMobil	2012	2032	8.2	7.2
Angola, Block 15: Marimba	13.33%	ExxonMobil	2007	2027	1.9	0.7
Angola, Block 15: Mondo	13.33%	ExxonMobil	2008	2029	5.7	1.3
Angola, Block 15: Saxi-Batuque	13.33%	ExxonMobil	2008	2029	7.9	2.0
Angola, Block 17: Dalia	23.33%	Total	2006	2024	45.2	14.8
Angola, Block 17: Girassol/Jasmim	23.33%	Total	2001	2022	25.9	8.8
Angola, Block 17: Pazflor	23.33%	Total	2011	2030	49.9	44.1
Angola, Block 17: Rosa	23.33%	Total	2007	2027	17.6	7.6
Angola, Block 31: PSVM	13.33%	BP	2012	2031	13.3	12.1
Nigeria: Agbami	20.21%	Chevron	2008	2024	47.0	39.3
Middle East and North Africa					67.4	33.3
Algeria: In Amenas	45.90%	Sonatrach/BP/Statoil	2006	2022	11.5	6.5
Algeria: In Salah	31.85%	Sonatrach/BP/Statoil	2004	2027	44.8	19.3
Libya: Mabruk	12.50%	Total	1995	2032	2.5	2.3
Libya: Murzuq	10.00%	Repsol	2003	2032	8.6	5.2
Europe and Asia					125.4	77.1
UK: Alba	17.00%	Chevron	1994	2018	2.8	2.8
UK: Jupiter	30.00%	ConocoPhillips	1995	2013	0.5	0.5
UK: Schiehallion [5]	5.88%	BP	1998	2017	0.1	0.1
Azerbaijan: ACG	8.56%	BP	1997	2024	56.1	21.8
Azerbaijan: Shah Deniz	25.5% [6]	BP	2006	2036	56.1	45.4
Russia: Kharyaga	30.00%	Total	1999	2032	9.7	6.4
Total Development and Production International (DPI)					723	502

(1) *In 2013, Statoil changed its policy for reporting U.S. entitlement volumes from including royalty volumes to excluding royalty volumes.*

(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 actual working interest can vary depending on wells and area.*

(4) *Petrocedeño is a non-consolidated company.*

(5) *Production from Schiehallion FPSO ceased in february 2013. A new FPSO is being built for Schiehallion redevelopment. Statoil sold its shares in Schiehallion in 4Q2013.*

(6) *Statoil has signed an agreement to divest a 10% share of its holding in Shah Deniz.*

The table below provides information about production per country in 2013.

Country	Average daily equity production [(1)] mboe/day	Average daily entitlement production [(2)] mboe/day
North America	225.7	188.4
Canada	21.5	21.5
USA	204.2	166.9
South America	43.1	43.1
Brazil	43.1	43.1
Sub-Saharan Africa	250.5	148.7
Angola	203.5	109.4
Nigeria	47.0	39.3
Middle East and North Africa	67.4	33.3
Algeria	56.4	25.8
Libya	11.0	7.5
Europe and Asia	125.4	77.1
Azerbaijan	112.3	67.3
Russia	9.7	6.4
UK	3.4	3.4
Total Development and Production International (DPI)	712	491
Equity accounted production		
Venezuela: Petrocedeño [(3)]	11.2	11.2
Total Development and Production International (DPI) including share of equity accounted production	723	502

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

(2) In 2013, Statoil changed its policy for reporting U.S. entitlement volumes from including royalty volumes to excluding royalty volumes.

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

The following sections provide information about the main producing assets internationally. See section *Financial review - Operating and financial review - DPI profit and loss analysis* for a discussion of the results of operations for 2013, 2012 and 2011.

3.6.2.1 North America

Production in North America comprises Canada and the USA. Statoil has gained operatorship in fast-growing Eagle Ford during 2013, making Statoil an operator in all three USA shale assets.

Canada

In 2007, we acquired 100% of the shares in North American Oil Sands Corporation and operatorship of 1,129 square kilometres (280,000 net acres) of oil sands' leases in the Athabasca region of Alberta that comprise the Kai Kos Dehseh (KKD) project. In January 2011, we formed a joint venture with PTTEP of Thailand and, as part of that transaction, sold them a 40% interest in KKD Oil Sands Partnership.

The **Leismer Demonstration Project (LDP)** is the first phase of the KKD development and has been in production since 2011. Operational performance has been successful and LDP successfully completed its first major plant turnaround in 2013.

In January 2014, Statoil and PTTEP signed an agreement to divide their respective interests in the Kai Kos Dehseh (KKD) oil sands project in Alberta, Canada, with effective date 1 January 2013. Following the transaction, Statoil will continue as operator and 100% owner for the Leismer and Corner development projects. PTTEP will own 100% of the Thornbury, Hangingstone and South Leismer areas. The completion of the transaction is subject to customary regulatory approvals in Canada and is expected to close by the third quarter of 2014.

In addition, we have interests in the offshore Jeanne d'Arc basin off Canada's East Coast in the producing fields **Hibernia** (Statoil interest 5%) and **Terra Nova** (Statoil interest 15%).

USA
Statoil has had a strong growth in production within US shale since we entered the first play in 2008, up to current level of 177 mboe/d in 2013.

Statoil entered the **Marcellus** shale gas play (located in the Appalachian region in north east USA) in 2008 through a partnership with Chesapeake Energy Corporation, acquiring 32.5% of Chesapeake's 1.8 million acres in Marcellus. We have continued to acquire acreage within the play, with a net acreage position of 611,000 acres, including 70,000 net acres acquired in December 2012 where we are now operating. Divestments of non-core acreage have also taken place during 2013 to highgrade our portfolio.

Marcellus provides Statoil with a long-life gas asset and considerable optionality in relation to the timing of drilling and production from these leases. Price development and continued improvement in operational efficiency are important variables in determining development plans.

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 line with the agreement with Talisman Energy Inc. from 2010. The transfer to operatorship was conducted as a phased process in order to maintain high HSE standards, and operational and business continuity. Statoil gradually took over operatorship, starting from the first quarter 2013, to obtain full operatorship of the Statoil operated acreage by the start of the third quarter of 2013. As a result of a few minor transactions, Statoil's net acreage position at the end of 2013 was 68,000 acres.

Statoil entered the **Bakken** and **Three Forks** tight oil plays through the acquisition of Brigham Exploration Company in December 2011. We are positioning ourselves as a leading player in the fast-growing US onshore oil and gas industry, which is in line with the strategic direction we have set out. Statoil has developed industrial capabilities step-by-step through early entrance into Marcellus and Eagle Ford. Taking on our first operatorship through Bakken represented a new significant step for us. Statoil's net acreage position in Bakken at the end of 2013 was 312,000 acres.

In deepwater Gulf of Mexico, the **Tahiti** oil field (Statoil interest 25%) is operated by Chevron. The field is located in the Green Canyon area. At the end of 2013, the field had eight producing wells and two water injectors connected to a floating facility.

The **Caesar Tonga** oil field (Statoil interest 23.55%) is operated by the Anadarko Petroleum Company. The field is located in the Green Canyon area. It consists of four wells tied back to the Anadarko-operated Constitution spar host. At the end of 2013, the field had three producing wells.

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.

Venezuela
Venezuela Statoil has a 9.7% interest in **Petrocedeño**, one of the largest extra-heavy crude oil projects in Venezuela. The field is located onshore in the Orinoco Belt area. Petrocedeño S.A, which is owned by project partners PDVSA, Total and Statoil, operates the field with related facilities and markets the products.

Petrocedeño's upgrader is still operating below design capacity. A major turnaround for the upgrader is expected to be executed in 2014.

3.6.2.3 Sub-Saharan Africa

Statoil's production activities in Sub-Saharan Africa comprise the Agbami project in Nigeria and four Angolan offshore blocks.

Angola
The Angolan continental shelf is the largest contributor to Statoil's production outside Norway. The main producing fields are **Pazflor, Dalia, Girassol/Jasmim and Rosa.**

Block 17 comprises production from three FPSOs; **Girassol**, **Dalia** and **Pazflor**. Block 17 is operated by Total, and Statoil holds a 23.3% interest.

Block 15 has production from four FPSOs: **Kizomba A** , **Kizomba B** , **Kizomba C-Mondo** and **Kizomba C-Saxi Batuque**. Block 15 is operated by Esso Angola, a subsidiary of ExxonMobil, and Statoil holds a 13.3% interest.

Block 4/05 has production from the Gimboa FPSO. Sonangol P&P is the operator for block 4/05 and Statoil holds a 20% interest.

Block 31 had its first year of full production in 2013. The oil is produced over the PSVM FPSO. BP is the operator for Block 31 and Statoil holds a 13.3% interest.

Nigeria
In Nigeria, Statoil has a 20.2% interest in the country's largest deepwater producing field, **Agbami,** where Chevron is the operator.

The National Assembly of Nigeria is still debating the Petroleum Industry Bill (PIB), which will most likely increase the government take if passed. The timing and outcome of the bill are uncertain.

Together with our partner Chevron, we have initiated arbitration against the national oil company NNPC concerning the interpretation of certain clauses in Oil Mining Licence (OML) 128 production sharing contract which covers Statoil's part of the Agbami field.

Through our ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field, for which the outcome is uncertain (see note 23 *Other commitments and contingencies* in the Consolidated financial statements).

3.6.2.4 Middle East and North Africa

Statoil had production in 2013 in the Middle East and North Africa from Algeria and Libya.

Algeria
The **In Amenas** onshore development is the fourth-largest gas development in Algeria. It contains significant liquid volumes. The facilities are operated through a joint operatorship between Sonatrach, BP and Statoil, where Statoil's share of the investments (working interest) is 45.9%. A contract of association, including mechanisms for revenue sharing, governs the rights and obligations of the 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 stable. It is still unclear when the third train will restart.

The **In Salah** onshore gas development in which Statoil has a working interest of 31.9% is Algeria's third-largest gas development. The field has produced at plateau level in 2013. A contract of association, including mechanisms for revenue sharing, governs the rights and obligations of the joint operatorship between Sonatrach, BP and Statoil.

Despite the absence of joint venture (JV) personnel, the In Salah field has had good and regular production throughout the year.

After the attack on **In Amenas** on 16 January 2013, Statoil withdrew all personnel from operational sites in Algeria. During the spring of 2013, work was conducted out of offices outside Algeria. The primary focus has been on improving security at all sites in preparation for a possible return to ordinary operations. At the end of October 2013, Statoil approved the return of personnel to ordinary rotation at the operations base in Hassi Messaoud. In January 2014, Statoil approved the resumption of ordinary rotation at Krechba and Hassi Moumene, two of the four In Salah Gas sites. The return of personnel to ordinary rotation at the last two In Salah Gas locations Reg and Teg and to In Amenas is conditional on the full implementation and verification of the necessary security requirements.

Libya

Statoil is a partner in two licences, Murzuq and Mabruk. Statoil has a 10% share of investments (working interest) in the NC 186 licence in the **Murzuq** field, which is operated by Akakus Oil Operations, with Repsol as the lead partner for the international oil companies. Statoil has a 12.5% share of investments (working interest) in the C-17 licence in the **Mabruk** field, which is operated by Mabruk Oil Operations. Total is the lead partner for the international oil companies in the C-17 licence Mabruk.

During 2013, there have been several production closures at both fields due to the security situation, including the production at Mabruk, which has been down since late July 2013. In December 2013, Statoil reduced its presence in Tripoli to a smaller office manned only by local staff.

3.6.2.5 Europe and Asia

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

Azerbaijan

Statoil has an 8.6% stake in the **Azeri-Chirag-Gunashli (ACG)** oil field and a 25.5% share in the **Shah Deniz** gas and condensate field. BP is the operator for both fields.

The **Chirag** Oil Project, the sixth platform on the ACG oil field, came on stream in late January 2014. It has a design capacity of 185 mboe per day.

Statoil has an 8.7% stake in the 1,760 km Baku-Tbilisi-Ceyhan (BTC) oil pipeline that is used to transport most of the ACG oil and Shah Deniz condensate to the southern Turkish port of Ceyhan, enabling liquids to be shipped to the world's markets.

Statoil has a 25.5% share in the South Caucasus Pipeline, which transports the Shah Deniz gas from Azerbaijan through Georgia to the eastern Turkish border. Statoil is the commercial operator of the South Caucasus Pipeline Company, responsible for commercial operations relating to the South Caucasus Pipeline. Statoil also runs the Azerbaijan Gas Sales Company, which was established to manage gas allocation and sales to customers in Azerbaijan, Georgia and Turkey.

In December 2013, Statoil signed an agreement to divest 10% of its 25.5% holdings in Shah Deniz and the South Caucasus Pipeline. The effective date of the transaction is 1 January 2014. The divestment is pending government approval and other conditions.

Russia

Statoil has a 30% share in the **Kharyaga** oil field onshore in the Timan Pechora basin in north-west Russia. The field is being developed in phases under a production sharing agreement (PSA), and it is operated by Total.

United Kingdom

In the UK, Statoil is a partner in two production licences. The **Alba** oil field (Statoil interest 17%) is located in the central part of the UK North Sea and is operated by Chevron. **Jupiter** (Statoil interest 30%) is a gas field located in the southern part of the UK North Sea. ConocoPhillips is the operator of this field.

3.6.3 International exploration

Statoil continued to have international exploration success in 2013.

In 2013 Statoil carried out significant international exploration activity, as is shown by the company's involvement in 24 completed wells (including both Statoil-operated and partner-operated activities). Seven wells (exploration and appraisal) were announced as discoveries in the period, including the Harpoon West and Bay du Nord (Statoil-operated) discoveries in Canada, as well as Tangawizi, which was Statoil's third discovery offshore Tanzania within one year. A total of nine wells were reported dry, while eight wells were under evaluation at the year end.

These results illustrate Statoil's strategy towards drilling significant targets and early entrance, with a large stake, into new plays. The emphasis hereby has been on accessing future core areas and focusing on play openers in order to expand from the current two core areas (Norway and Gulf of Mexico) to a potential six with the emerging core areas Angola, Brazil, East Africa and East Canada.

For that reason Statoil also secured new acreage globally in 2013. In Australia, Statoil signed a farm-in agreement with BP in May, which gives Statoil a 30% interest in four offshore licenses. Furthermore, Statoil assumed operatorship for four licenses regarding unconventional exploration onshore Australia through an agreement with Petrofrontier. Another licensing round milestone was the award of six licences in the Espirito Santo basin, won in the 11th licensing round in Brazil in May, the first licensing round in the country since December 2008.

Statoil was awarded 17 leases in the Central and Western US Gulf of Mexico (GoM) lease sales in 2013.

In June, Statoil and Rosneft signed agreements that completed the contractual framework of their joint venture to explore offshore frontier areas in the Sea of Okhotsk and the Barents Sea. Statoil has an equity share of 33.33% and Rosneft 66.67% in each of the operating companies established to explore the offshore licences. In December, the two companies signed the Shareholders and Operating Agreement to explore shale oil opportunities in the Samara region. Rosneft's stake in the project is 51%, while Statoil holds 49%.

In December, Statoil obtained a 100% equity share in an exploration permit in the Reinga-Northland Offshore Release Area in the New Zealand Block Offer 2013. The permit covers approximately 10,000 square kilometres and is located approximately 100 kilometres from shore to the west of New Zealand's North Island, in water depths ranging from 1,000 to 2,000 metres.

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

		2013	2012	2011
North America	- Statoil operated	7	3	2
	- Partner operated	4	6	4
South America/sub-saharan Africa	- Statoil operated	6	5	3
	- Partner operated	4	7	4
Middle East and North-Africa	- Statoil operated	0	0	1
	- Partner operated	1	1	0
Europe and Asia	- Statoil operated	0	3	0
	- Partner operated	2	2	2
	Totals	24	27	16

The regions where Statoil had exploration activity in 2013 are presented below.

North America

USA

Statoil operated two wells in the Gulf of Mexico (Candy Bars exploration well and Logan appraisal well), which were dry, and participated in four additional partner operated wells, of which the appraisal well Vito 2 SW Sidetrack was a discovery. Operator Shell and its partners are currently working to progress this project. Statoil still has a number of promising prospects in its GoM portfolio and is aiming to continue its drilling activities in 2014.

Canada

The Bay du Nord oil discovery, located approximately 500 km northeast of St. John's, Newfoundland and Labrador, was announced in August. It is Statoil's third discovery in the Flemish Pass Basin after Mizzen (2009) and the Harpoon discovery, announced in June. While the volumes are significant, the Flemish Pass Basin is still considered an exploration play. With only a few wells drilled in a large area, totalling about 8,500 square kilometres, more work is required. We therefore consider this discovery at Bay du Nord in the Flemish Pass Basin to be still in the exploration and appraisal phase, though it has the potential to become a core producing area for Statoil post-2020.

South America and sub-Saharan Africa

Angola

Statoil has acquired a key position in the pre-salt play of the Kwanza basin. In January 2013 Statoil (with Total and BP) completed a large 3D survey across its licences in the Kwanza basin offshore Angola. The survey covers 26,300 square kilometres, equivalent to most of the Norwegian sector of the North Sea, or more than 70 blocks on the Norwegian continental shelf. In-house processing of seismic data and prospect evaluation for the basin is ongoing. The test of the Kwanza portfolio through drilling will be conducted during the second half of 2014. Statoil will drill its first well Dilolo-1 in Block 39 in May 2014, more or less in parallel with wells in the partner-operated Blocks 25 and 22. Subsequent wells will be drilled in Blocks 38 (Statoil) and 40 (Total). By the end of 2014 up to six wells are expected to be drilled (some may complete in 2015).

Brazil

In May 2013, Statoil was awarded six licences offshore Brazil in Brazil's 11th licensing round, of which Statoil is the operator for four. The total firm appraisal programme for the awarded blocks is 4500 km2 of 3D seismic and ten exploration wells of which Statoil will operate four. Seismic acquisition will start in 2014. In the BM-C-33 licence, operated by Repsol, appraisal drilling of the Seat and Pão de Açúcar pre-salt discoveries is ongoing with the objective to mature a field development decision. In the BM-C-47 licenses, adjacent to the Peregrino field, the last remaining commitment well on the Juxia prospect will be drilled in the first quarter of 2014. In the Petrobras operated licences BM-ES-32 and BM-ES-22A, appraisal work is planned on the Indra and São Bernardo discoveries. Statoil has purchased Vale's 25% share in the BM-ES-22A licence. The purchase is subject to authority approval.

Mozambique
Statoil farmed down a 25% working interest in its operated exploration licence offshore Mozambique during the first quarter to Japan-based INPEX Mozambique, Ltd. The licence consists of two blocks under one licence agreement, and is located in areas 2 and 5 offshore Mozambique in the Rovuma basin. The blocks are located in a frontier area with a water depth varying between 300 and 2,500 metres. The area covers 8,041 square kilometres. Meanwhile, the Cachalote-1/1A and Buzio-1 wells were completed in September 2013 and are defined as dry with only an uncommercial gas discovery. The post-well analysis is ongoing. The licence expires in 2014.

Tanzania
The discoveries of natural gas in Tangawizi-1 during the first quarter and Mronge-1 in December significantly increased the total in-place volumes in Block 2. Statoil and partner ExxonMobil are also working to mature additional prospects in Block 2 and have completed the acquisition of additional 3D seismic data in those areas of Block 2 hitherto only covered by 2D seismic.

In May 2013 Statoil acquired a 12% working interest in Block 6 from operator Petrobras Tanzania Ltd. Block 6 covers 5,549 square kilometres in the Mafia basin offshore Tanzania, with a water depth of 1,800 metres. Block 6 is located approximately 170 kilometres north of the Statoil-operated Block 2, where the company made further gas discoveries in 2012 and 2013.

Current operation with Discoverer Americas is a production test (DST) in the Zafarani-2 well. Thereafter, the plan is to drill a second appraisal well on the Zafarani discovery before commencing new exploration drilling in Q2/Q3, drilling 2-3 new wildcat wells before the end of 2014.

Middle East and North Africa

Azerbaijan
A Memorandum of Understanding (MoU) for the exploration and development of the Zafar Mashal offshore block in Azerbaijan was signed in April 2013 by Statoil and the State Oil Company of the Republic of Azerbaijan (SOCAR). The South Caspian basin contains a rich petroleum system and this opportunity fits in very well with Statoil's exploration strategy of gaining access at scale.

In addition Statoil and SOCAR are pursuing evaluation of a large Joint Study Area in the Caspian Sea, north of the Absheron peninsula.

Europe (excluding Norway), Asia and Australia

UK
In 2012 and 2013 Statoil was awarded interests in eight exploration licenses in the UK 27th licensing round. The company's interests range from 20% to 60% and Statoil is the operator for three of the licences, in addition to shared operatorship with Nexen on one licence.

In 2014, Statoil will participate in the drilling of two UK North Sea exploration wells. Hadrian/Kookaburra in block 28/15 was spudded in February 2014 to test the oil potential in one of the main prospects awarded in the 27th licensing round. In Q2 2014 Statoil will drill the Wall prospect in the same block. To gain access to further acreage, we are preparing to submit bids in the 28th UK licensing round.

Greenland
Statoil, along with partners ConocoPhillips and Nunaoil, was awarded block 6 in the East Greenland license round in December 2013. Statoil will be operator of the block. The licence has a 16-year exploration period. The first work to be carried out will be seismic acquisition, after which a decision on further work will be made. Statoil previously carried out both shallow core drilling and scientific work in the area to understand the operating environment.

Faroe Islands
In Q2 2014 Statoil will resume drilling of the Brugdan II well in license 006, which was suspended in 2012 due to weather conditions. Upon completion of the Brugdan II well, Statoil will move the rig to license 008, close to the UK-Faroes border, to drill the Sula Stelkur prospect.

Russia
In June 2013 Statoil and Rosneft signed agreements that complete the contractual framework of their joint venture to explore offshore frontier areas in the Sea of Okhotsk and in the Barents Sea. An acquisition of 2D seismic data in the Sea of Okhotsk was completed in September 2013. The requirements for the four offshore licences operated by the Rosneft-Statoil joint-venture include the drilling of six exploration wells in the period from 2016 to 2021.

In December 2013 Statoil and Rosneft signed the shareholders and operating agreement for a joint venture to assess the feasibility of commercial production from the Domanik shale formation. The companies will set up a joint venture (JV) company to run a three-year pilot programme and assess the potential for commercial production. The pilot programme will include data acquisition, and the drilling and hydraulic fracturing of pilot wells in twelve licence blocks in the Samara region.

Indonesia
The Cikar-1 well in the West Papua IV license was temporarily suspended by the operator Niko in March 2013 and is still under evaluation. Statoil is currently evaluating several follow-up opportunities in this licence and the neighbouring Aru licence. 2D seismic data acquisition in the Statoil-operated Halmahera II PSC was completed in July 2013 and data processing is ongoing. All well commitments were fulfilled in North Makassar PSC, the West Papua IV PSCs and the Kuma and Karama PSCs.

Australia
In April 2013 Statoil signed a farm-in agreement with BP, acquiring a 30% equity share in four licences in the frontier Ceduna Sub Basin within the Great Australian Bight, off the coast of South Australia, where BP previously held 100%. The basin requires competencies that are core to Statoil: Deep water, harsh environment, co-existence with other industries and high HSE standards. All other Mesozoic deltas in Australia have been explored and are producing hydrocarbons. BP has completed an extensive 12,000 square km 3D seismic survey. The next steps include the maturation of drillable prospects and continued environmental studies.

In September 2013 Statoil took over as operator, acquiring a 80% equity share from PetroFrontier, in four unconventional exploration licences, onshore in the Northern Territory. The current work programme for 2014 includes the drilling of up to 5 exploration wells, extensive data collection and the permanent abandonment of three wells drilled by the former operator.

New Zealand
In December 2013, Statoil obtained 100% equity share in an exploration permit in the Reinga-Northland Offshore Release Area in the New Zealand Block Offer 2013. The permit covers approximately 10,000 square kilometres and is located approximately 100 kilometres from shore to the west of New Zealand's North Island, in water depths ranging from 1,000 to 2,000 meters. The work program is designed to fully evaluate the prospectivity of the permit in a staged manner within the 15-year permit timeframe. Statoil is committed to obtain new 2D seismic data and to undertake a multibeam seafloor survey with selected core samples within the first three years, after which Statoil will decide on further steps.

3.6.4 Fields under development internationally

The main sanctioned development projects in which DPI is involved are in Angola, Azerbaijan, Canada, the UK and the USA. We believe we are well positioned for further profitable growth through a substantial pre-sanctioned project portfolio.

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

Sanctioned projects coming on stream 2014-2015 *	Statoil's share at 31 December 2013	Operator	Time of sanctioning	Production start
Angola: Block 17, CLOV	23.33%	Total	2010	2014
USA: Jack	25.00%	Chevron	2010	2014
USA: St. Malo	21.50%	Chevron	2010	2014
USA: Big Foot	27.50%	Chevron	2010	2015
Canada: Hibernia South Extension	10.50%	Exxon Mobil	2011	2014
Algeria: In Salah Southern Fields	31.85%	Sonatrach/BP/Statoil	2010	2015
Algeria: In Amenas Compression project	45.90%	Sonatrach/BP/Statoil	2010	2015

* Not exhaustive

3.6.4.1 North America

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

USA Gulf of Mexico
Tahiti Phase 2 (Statoil interest 25%), operated by Chevron, will add two producing and three water-injection wells to the Tahiti field. Injection from the first two water-injection wells started in 2012, with the third injector currently expected to come on stream by the end of 2014. One producer came on stream in 2013 and the second well is currently been drilled.

Statoil has a 25% working interest in the **Jack** oil field and a 21.5% working interest in **St. Malo** oil field, located in Walker Ridge. The two fields are operated by Chevron and will be developed jointly with subsea wells connected to a centrally located production platform. First oil is expected late 2014.

Statoil has a 27.5% interest in **Big Foot** located in Walker Ridge block 29. Big Foot is operated by Chevron and will be developed with a dry tree tension leg platform with a drilling rig. First oil from Big Foot is currently scheduled for mid-2015, delayed from 4Q 2014. The project has not made the fabrication progress as planned which has caused the delayed start up.

Discovered in 2007, Statoil has a 50% working interest in the **Julia** field located in Walker Ridge area of the Gulf of Mexico, which comprises five blocks. Julia is one of the major discoveries in the Paleogene. Exxon Mobil is the operator and the field will be developed with subsea wells tied back to the Jack-St. Malo production platform. First oil is expected in mid-2016.

Statoil has a 12% interest in **Heidelberg** located in Green Canyon block 859. Heidelberg is operated by Anadarko Petroleum Corp. and was sanctioned in April 2013. Project development includes a SPAR and subsea trees. First oil from Heidelberg is scheduled for mid-2016.

USA Onshore
In addition to offshore development projects, North America production growth is also boosted significantly by the continued ramp-up from the shale plays Bakken, Eagle Ford and Marcellus (Chapter 3.6.2.1. for further information).

Canada
In **Canada**, Statoil has a 60% interest and is the operator of the KKD Oil Sands Partnership. The first phase, the Leismer Demonstration Project, came on stream in early 2011. The **Corner** project is in the project definition phase and continues to be brought to maturity. The **Leismer Expansion** project is in the concept planning phase.

In January 2014, Statoil and PTTEP signed an agreement to divide their respective interests in the Kai Kos Dehseh (KKD) oil sands project in Alberta, Canada. See section *Business overview - Development and Production International (DPI) - International Production - North America* for further information.

Statoil has a 10.5% interest in the Exxon-operated **Hibernia tie-in** project (a satellite of Hibernia) where all wells are expected to be on stream in 2014.

Offshore Newfoundland, Statoil has a 9.7% interest in the Exxon-operated **Hebron** field located in the Jeanne d'Arc basin near the other partner-operated fields Terra Nova and Hibernia. First oil is expected in 2017. The Hebron field will be developed using a fixed gravity base structure (GBS).

3.6.4.2 South America

In early 2014 the concept for Peregrino Phase II project in Brazil was selected.

On 28 January 2014, Statoil approved the concept selection for the development of the second phase of the Peregrino oil field. 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 2013, Statoil had several ongoing field development projects in Angola.

Angola
In **Block 17**, **Angola,** the **CLOV** project, consisting of the Cravo, Lirio, Orchidea and Violeta discoveries, was approved in 2010. The first oil is expected in 2014. CLOV will be produced by a new FPSO. Block 17 is operated by Total, and Statoil holds a 23.3% interest.

In **Block 15, Angola**, the **Kizomba Satellites phase 2** project, which consists of the discoveries Bavuka, Kakocha, and Mondo South, was approved in 2013. The phase 2 project includes subsea tiebacks to existing Kizomba B and Mondo FPSO vessels. Block 15 is operated by Esso Angola, a subsidiary of ExxonMobil, with Statoil holding a 13.3% interest in this block.

In Block 15/06, **Angola,** the West Hub, which is the first development project on this block, was approved in 2010. The project comprises several oil discoveries which will be produced over an FPSO. Production start is scheduled for 2015. Block 15/06 is operated by Eni, and Statoil's interest is 5%.

3.6.4.4 Middle East and North Africa

In 2013, Statoil's field development in the Middle East and North Africa was focused on Algeria.

The **In Salah Southern Field Development Project** in Algeria was sanctioned in late 2010. This project, which is led by Statoil on behalf of the Joint Venture, will mature the remaining four discoveries into production and it is currently scheduled to come on stream in 2015. The delay is due to the In Amenas terrorist attack on 16 January 2013. The southern fields will tie in to existing facilities in the northern fields.

A contract of association, including mechanisms for revenue sharing, governs the rights and obligations of the joint operatorship between Sonatrach, BP and Statoil. Statoil's working interest is 31.9%.

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 2015. This will make it possible to reduce wellhead pressure and maintain the contractual production commitment.

The In Amenas facilities are operated through a joint operatorship between Sonatrach, BP and Statoil. Statoil has a 45.9% working interest in In Amenas.

The **Hassi Mouina** exploration licence expired in September 2012. We still aim to develop the field, but need to reach agreement with the Algerian authorities on commercial terms.

3.6.4.5 Europe and Asia

In Europe and Asia, Statoil is participating in the planning and development of projects in Azerbaijan, the United Kingdom, Russia, and Ireland.

Azerbaijan

In December 2013, Statoil and its partners in the Shah Deniz consortium made the final investment decision for the development of the Stage 2 development of the Shah Deniz gas field in Azerbaijan and expansion of the South Caucasus Pipeline (SCPX) through Azerbaijan and Georgia. The stage 2 project includes offshore drilling and completion of 26 subsea wells, and the construction of two bridge-linked platforms. First gas from stage 2 is targeted for late 2018. Statoil has a 25.5% interest in Shah Deniz.

The South Caucasus Pipeline (SCPX) through Azerbaijan and Georgia, the Trans Anatolian Gas Pipeline (TANAP) across Turkey, and the Trans Adriatic Pipeline (TAP) across Greece, Albania and into Italy will together create a new Southern Gas Corridor to Europe. Statoil holds a 25.5% share in SCPX and a 20% share in TAP AG, the owner of the Trans Adriatic Pipeline (TAP). Statoil will not participate as an investor in TANAP.

In December 2013, Statoil signed an agreement to divest a 10% share of its 25.5% holdings in Shah Deniz and the South Caucasus Pipeline. The effective date of the transaction is 1 January 2014. The divestment is pending government approval and other conditions.

United Kingdom

Statoil is the operator for the **Mariner** heavy oil project and holds a 65.1% interest. 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 first oil in early 2017.

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 and holds a 92% interest.

Statoil is the operator for, and holds an 81.6% interest in **Bressay**. Bressay is also a heavy oil discovery. Investment decision on Bressay has been postponed and alternative development solutions are currently under evaluation.

Ireland

Statoil has a 36.5% interest in the **Corrib** gas field operated by Shell, which is being developed as a subsea tie back to an onshore processing facility. The onshore processing terminal is located approximately 9 km inland. Most of the terminal was completed in 2013. Tunnelling to accommodate the onshore pipeline started in December 2012 and first gas will depend on the duration of the tunnelling work and the timing of permits required for the operation of the field. The operator targets production start-up in the second half of 2015.

3.7 Marketing, Processing and Renewable Energy (MPR)

3.7.1 MPR overview

Marketing, Processing and Renewable Energy (MPR) is responsible for the marketing and trading of crude oil, natural gas, liquids and refined products, for transportation and processing, and for developing business opportunities in renewables.

MPR markets Statoil's own volumes and the Norwegian state's direct financial interest (SDFI) equity production of crude oil, in addition to third-party volumes.

MPR is also responsible for marketing gas supplies relating to the SDFI. In total, we are responsible for marketing approximately 70% of all Norwegian gas exports.

MPR is responsible for running two refineries, two gas processing plants, one methanol plant and three crude oil terminals. In addition, we are responsible for the development of export solutions for natural gas and liquids from the Statoil assets, and will construct pipelines to facilitate this over the next few years. Furthermore, we are responsible for developing a profitable renewable energy position.

In 2013, we sold 36.3 billion cubic metres (bcm) of natural gas from the Norwegian continental shelf (NCS) on our own behalf, in addition to approximately 35.4 bcm of NCS gas on behalf of the Norwegian state. Statoil's total European gas sales, including third-party gas, amounted to 84.1 bcm in 2013, 38.7 bcm of which was gas sold on behalf of the Norwegian state. That makes Statoil the second-largest gas supplier to Europe. The largest supplier is Gazprom. Statoil's total US gas sales, including third-party gas, amounted to 15.06 bcm in 2013, 0.9 bcm of which was gas sold on behalf of the Norwegian state.

In 2013, we also sold 635 million barrels of crude oil and condensate, approximately 25 million tonnes of refined oil products from our own refineries, and approximately 15 million tonnes of natural gas liquids (NGL). Tjeldbergodden produced approximately 0,8 million tonnes of methanol. Our international trading activities make Statoil one of the world's largest net crude oil sellers.

In 2013, the gas market was characterised by good customer off-take, but lower market prices than in 2012. Refinery margins were lower than in 2012. The operation of facilities has been stable, and HSE results are within our target for the year.

With effect from 1 May 2014, MPR has decided to combine all marketing and trading activities into one business cluster. A separate asset management business cluster will also be established with the responsibility for financial ownership and commercial operations of all mid- and downstream assets.

The MPR business activities were organised in the following business clusters in 2013: Natural gas; Crude oil, liquids and products; Processing and manufacturing; and Renewable energy. This structure is followed in the discussion of MPR's business activities below.

Key events in 2013:

- The Shah Deniz Consortium, in which Statoil has an ownership interest, announced 25-year sales agreements for just over 10 bcm per year with European customers.
- A final investment decision was made for the stage 2 development of Shah Deniz. Concurrently Statoil has signed an agreement to divest a 10% share of its 25.5% holdings in the Shah Deniz and the South Caucasus Pipeline to SOCAR (6.7%) and BP (3.3%).
- With effect from the first of September 2013, Statoil has acquired 100% of the shares in Dong Generation Norge AS, which holds the ownership of the Mongstad combined heat and power plant.
- With effect from the first of January 2014 Statoil has acquired Shell's 21% share in the Mongstad refinery in Norway and sold its 10% share in the Pernis refinery in the Netherlands to Shell. As a result of these agreements, Statoil is the 100% owner of the Mongstad refinery, whereas Shell owns 100% of the Pernis refinery.
- With effect from 1 November 2013, Statoil is marketing and delivering gas from the Marcellus field to New York city.

3.7.2 Natural Gas

The natural gas business cluster (NG) 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.

In addition, NG is responsible for marketing gas related to the Norwegian state's direct financial interest (SDFI) and for managing Statoil's asset ownership in gas infrastructure, such as the processing and transportation system for Norwegian gas (Gassled) and gathering and processing in the Marcellus shale gas play.

NG's business is conducted from Norway (Stavanger) and from offices in Belgium, the UK, Germany, Turkey, Azerbaijan and the US (Stamford).

NG is a significant shipper in the NCS pipeline system owned by Gassled, which is the world's largest offshore gas pipeline transportation 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. This gives Statoil access to customers throughout Europe.

By the end of 2013, Statoil had a 5% ownership interest in the Gassled transportation system.

3.7.2.1 Gas sales and marketing

Statoil transports and markets approximately 70% of all NCS gas and has a growing US gas position. In Europe, the gas is sold through long-term contracts with major European utilities, and a growing proportion through short term end-user sales and on liquid marketplaces.

Due to the relatively large size of the NCS gas fields and the extensive cost of developing new fields and gas transportation pipelines, a large proportion of Statoil's gas sales contracts are long-term contracts that typically run for 10 to 20 years or more.

These sales are carried out with large industrial customers, power producers and local distribution companies, and through short-term contracts and trading on European liquid marketplaces both in the UK and on the European Continent. In the USA, gas is sold through a mix of contracts and trading on liquid marketplaces.

Most of the traditional 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. With the recent gas market development ongoing in many regions in Europe, Statoil has used the price reviews to agree on structural solutions for the long term gas contracts with several of its customers. Key characteristics are a gradual transition from oil indexation towards gas-hub related pricing, as well as a reduction of the buyer's daily and annual flexibility. Statoil is currently in price reviews with some of our 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 opportunities. This is done both as a response to customer needs and in order to capture new business opportunities as the markets become more liberalised.

Europe
The major export markets for gas from the NCS are Germany, France, the UK, Belgium, Italy, the Netherlands and Spain. The majority of the gas is sold through long-term contracts. Our main customers are large national or regional gas companies such as GdF Suez, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), RWE and GasTerra. We are also expanding our marketing of gas to large industrial customers, power producers and local distribution companies, in addition to making spot-market sales.

Our groupwide gas trading activity is mainly focused on the UK gas market NBP (National Balancing Point UK), which is a significant market in terms of size and the most liberalised market in Europe. We have also increased our activities in continental marketplaces, mainly in the Netherlands, but also in Germany, France and Belgium.

Statoil UK holds one third share of the interests in the Aldbrough Gas Storage, operated by SSE Hornsea Ltd. At the end of 2013 seven out of nine caverns were operational.

In Germany, we hold a 30.8% stake in the Norddeutche Erdgas Transversale (NETRA) overland gas transmission pipeline and a 23.7% stake in Etzel Gas Lager.

USA

The USA 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 USA over the last years.

SNG has entered into gas transportation agreements with Tennessee Gas Pipeline (a subsidiary of El Paso Corp), and Texas Eastern Transmission (a subsidiary of Spectra Energy Corp), for a total capacity of approx. 2 billion cubic metres (bcm) per year, approx. 205,000 MMBtu/day, enabling Statoil to transport gas from the Northern Marcellus production area to Manhattan, NY. This commenced service on 1st November 2013 for a term of 20 years.

SNG has also entered into a gas transportation agreement with the National Fuel Gas Supply Corporation for a total capacity of 3.2 billion cubic metres (bcm) per year, approx.320,000 MMBtu/day, enabling Statoil to transport gas from the Northern Marcellus production area to the US/Canadian border at Niagara, providing access to the greater Toronto area in Canada. The National Fuel pipeline commenced service on 1 November 2012 for a term of 20 years.

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 10.9 bcm per year. An onerous contract provision of NOK 4.1 billion has been recognised in 2013 related to these contracts.

LNG is sourced from the Snøhvit LNG facility in Norway. Due to continuing low gas prices in the USA, no Statoil LNG cargoes have been delivered to the USA, Instead, Statoil's LNG cargoes have been diverted away from the US and delivered into higher-priced markets in Europe, South-America and Asia.

Azerbaijan

Statoil has an ownership share in the Shah Deniz gas/condensate field in Azerbaijan and is the commercial operator for gas transportation as well as the operator of marketing and sales of gas from Shah Deniz stage 1. In addition, Statoil heads up the Gas Commercial Committee and plays a key role in the gas export negotiation committee for the Shah Deniz stage 2 project. Azerbaijan, Georgia and Turkey are part of the gas sales portfolio for stage 1, in which Turkey constitutes the main market.

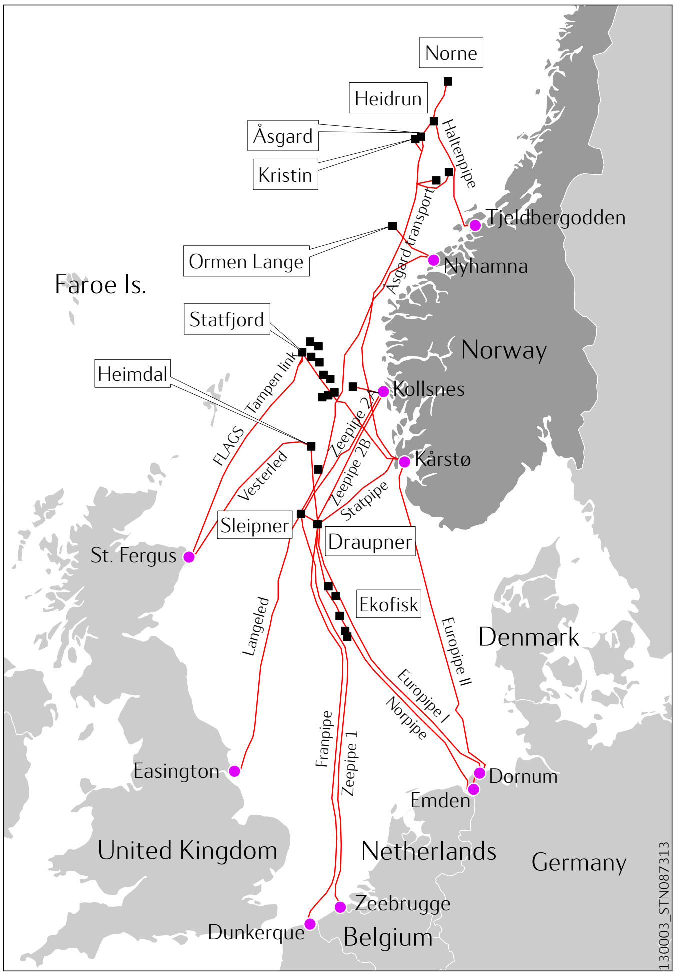
For the stage 2 development of Shah Deniz, a final investment decision was made 2013. In June 2012, the governments of Turkey and Azerbaijan signed an inter-governmental agreement relating to the development of an independent pipeline for the transit of gas across Turkey. During the first half of 2012 the Shah Deniz consortium reduced the number of competing pipelines for the further transportation of gas into the European markets to one in the Italian corridor and one in the corridor leading to Baumgarten, Austria. Together with key partners in Shah Deniz, the consortium in 2013 entered into gas sales contracts with nine European buyers of 10 BCM for a 25-year period, contingent on field investment decision.

Algeria

Statoil has ownership interests in the In Salah and In Amenas gas fields, Algeria's third-largest and fourth-largest gas developments, respectively. Statoil receives its income for In Salah production from gas which is sold under long-term contracts, mainly to Europe.

3.7.2.2 The Norwegian gas transportation system

Over the last 30 years, the Norwegian gas pipeline system has been developed into an integrated system connecting gas-producing fields on the Norwegian continental shelf (NCS) with receiving terminals in Europe via processing plants on the Norwegian mainland.



The total length of Norway's gas pipelines is currently 8,100 kilometres, and all 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. Statoil is the technical service provider (TSP) for Gassco with respect to the Kårstø and Kollsnes processing terminals, as well as for most of the gas pipeline and platform infrastructure system.

In 2011, Statoil divested 24.1% of its ownership interest in Gassled, and its ownership interest is now 5.0%. Statoil is the largest shipper in Gassled.

When new gas infrastructure facilities are merged into Gassled, the ownership interests are adjusted in relation to the relative value of the assets and each owner's relative interest. Hence, Statoil's future ownership interest in Gassled may change as a result of the inclusion of new fields and infrastructure.

3.7.2.3 Processing

Statoil is the technical services provider (TSP) for the operation, maintenance and further development of large parts of the gas infrastructure on the NCS on behalf of the operator Gassco.

Kollsnes gas processing plant

Statoil is the technical services provider (TSP) for the operation, maintenance and further development of the Kollsnes gas processing plant on behalf of the operator Gassco.

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 gas processing plant

Statoil is the technical services provider for the operation, maintenance and further development of the Kårstø gas processing plant on behalf of the operator Gassco.

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 stabilized condensate. The dry gas is transported to customers through the Gassled pipeline network via receiving terminals in Europe.

3.7.3 Crude oil, liquids and products

The crude oil, liquids and products business cluster (CLP) adds value through the sale of the group's and the Norwegian state's direct financial interest (SDFI) production of crude oil and natural gas liquids.

CLP is responsible for the group's transportation, marketing and trading of crude oil, natural gas liquids and refined products, including methanol. CLP is also responsible for the commercial operation of the two refineries at Mongstad, Norway and Kalundborg, Denmark, and for the commercial operation of the crude oil terminals at Mongstad, Norway and at South Riding Point, Bahamas. In addition, CLP is responsible for managing Statoil's asset ownership in gathering and processing of Eagle Ford shale gas and Bakken shale oil. Production from Eagle Ford is primarily transported by pipeline while crude oil from Bakken is for the most part transported to the best paying markets by rail. CLP is the asset owner for two oil transportation pipelines on the NCS, the Johan Sverdrup Oil Pipeline and the Edvard Grieg Oil Pipeline.

In 2013, CLP sold 635 million barrels of crude oil and condensate, approximately 25 million tonnes of refined oil products and 15 million tonnes of natural gas liquids (NGL).

3.7.3.1 Marketing and trading

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

Statoil markets its own volumes and the Norwegian state's direct financial interest (SDFI) equity production of crude oil and NGL, in addition to third-party volumes. In 2013, MPR sold 635 million barrels of crude and condensate, including supplies to our own refineries, and 174 million barrels of NGL volumes. The main crude oil market for Statoil is north-west Europe. In addition, volumes are sold to North America and Asia. Most of the crude oil volumes are sold on the spot market, based on publicly quoted market prices. Of the total 635 million barrels sold in 2013, approximately 44% represented Statoil equity volumes, while approximately 40% of the total 174 million barrels of NGL sold in 2013 were Statoil equity volumes.

The CLP business cluster is responsible for optimising commercial utilisation of the crude terminal located at Mongstad and the South Riding Point crude oil terminal in the Bahamas. We are also responsible for Statoil's crude and liquefied petroleum gas (LPG) liftings at the Sture terminal, as well as Statoil's naphtha lifting from Kårstø and Braefoot Bay, and liftings of LPG from Kårstø, Mongstad, Braefoot Bay and Teeside terminals. We lift waterborne ethane from Kårstø and Teesside, and condensate and LPG volumes from Melkøya.

In addition, we market 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 on the spot market based on publicly quoted prices. CLP also markets equity volumes from several DPI assets worldwide.

Marketing activities are also optimised through the use of lease contracts and long-term agreements for the utilisation of third-party assets such as terminals, storages, pipelines, railcars and vessels.

3.7.3.2 Terminals and storage

We operate the Mongstad terminal and share ownership of it with Petoro. We also hold the lease for the South Riding Point crude oil terminal in the Bahamas, which includes crude oil storage and blending as well as loading and unloading facilities.

South Riding Point
The terminal, which is located on Grand Bahamas Island, consists of two shipping berths and ten storage tanks 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 ambitions and improve our handling capacity for heavy oils. The terminal is an integral part of our marketing of equity volumes of heavy oil.

Mongstad terminal
Statoil operates the Mongstad terminal, which has a storage capacity of 9.4 million barrels of crude oil. Statoil has an ownership interest of 65%, while Petoro holds 35%.

Crude oil is landed at Mongstad via two pipelines from Troll, by dedicated vessels from Heidrun, and by crude vessels from the market.

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.

3.7.4 Processing and manufacturing

The Processing and manufacturing business cluster is responsible for the operation of all of Statoil's onshore facilities in Norway and Denmark except for Snøhvit related facilities.

This includes the refineries at Mongstad and Kalundborg, the methanol production plant at Tjeldbergodden and the gas processing plants at Kårstø and Kollsnes.

Processing and manufacturing is also responsible for the operation of the Oseberg transportation system, Grane oil pipeline, Kvitebjørn oil pipeline, Troll oil pipeline I and II, and Mongstad gas pipeline.

Up until 1 January 2014 Statoil owned 10% of the production capacity at the Shell-operated refinery in Pernis in the Netherlands, which has a crude oil distillation capacity of approximately 400,000 barrels per day. Statoil has agreed to sell its 10% share to Shell, with effect from the aforementioned date.

Processing and manufacturing 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. Processing and manufacturing also performs the TSP role for Transport Net (Norway's gas transport system) and the Mongstad terminal. For further information about Kårstø, Kollsnes, Transport Net and Mongstad terminal, see the section *Business overview - Marketing, Processing and Renewable Energy - Natural Gas* and *Crude oil, liquids and products*, respectively.

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

All data for year ended 31 December	Throughput [1]			Distillation capacity [2]			On stream factor % [3]			Utilisation rate % [4]		
Refinery	2013	2012	2011	2013	2012	2011	2013	2012	2011	2013	2012	2011
Mongstad	**11.8**	11.9	11.3	**9.3**	9.4	9.3	**98.9**	95.2	98.4	**95.0**	92.7	89.9
Kalundborg	**5.0**	4.9	4.4	**5.4**	5.4	5.4	**98.2**	94.4	99.2	**86.5**	88.9	86.4
Tjeldbergodden	**0.79**	0.81	0.86	**0.95**	0.95	0.95	**94.4**	86.4	97.2	**96.6**	97.5	97.3

(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.

(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.

Mongstad
Statoil is in 2013 the majority owner (79%) and operator of the Mongstad refinery in Norway, which has a crude oil and condensate distillation capacity of 240,000 barrels per day. The Mongstad refinery is linked to offshore fields, the Sture crude oil terminal and the Kollsnes gas processing plant, making it an attractive site for landing and processing of hydrocarbons. Effective from 1 January 2014, Statoil has agreed to buy Shell's 21% share in the Mongstad refinery.

The Mongstad refinery, which was built in 1975, was significantly expanded and upgraded in the late 1980s. 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, and 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.

In addition to the refinery, the main facilities at Mongstad consist of a crude oil terminal (Mongstad terminal), an NGL process unit and terminal (Vestprosess), and a combined heat and power plant (CHP). Statoil owns 65% of the crude terminal. A large proportion of its crude oil comes via two direct pipelines from the Troll field. The storage capacity is 9.4 million barrels of crude.

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.

With effect from 1 September 2013, Statoil acquired 100% of the shares in Dong Generation Norge AS, the owner of the Mongstad combined heat and power plant, which produces electrical heat and power from gas received from Kollsnes and from the refinery. The CHP plant 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 is the sole owner and operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 118,000 barrels per day. The Kalundborg refinery is a small but 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 two pipelines (one gasoline and one gas oil) to the terminal at Hedehusene near Copenhagen, and most of its products are therefore sold locally. Kalundborg's refined products are also supplied to other markets in north-western Europe, mainly to Scandinavia.

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 81.7% 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.

Sture

The Sture terminal receives crude oil in two pipelines from the Oseberg area and the Grane field 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 and Grane crude qualities and LPG mix are exported. LPG and naphtha are also transported through the Vestprosess pipeline to Mongstad.

3.7.5 Renewable energy

Our renewable energy business focuses on developing business in areas where we have a competitive edge as a result of our offshore oil and gas expertise. Offshore wind and carbon capture and storage are key areas.

Sheringham Shoal

The Sheringham Shoal wind farm, located off the coast of Norfolk, UK, was formally opened in September 2012. The wind farm is now in full production with 88 turbines and an installed capacity of 317 megawatt (MW). It is owned jointly with Statkraft, a Norwegian wholly state-owned company. The wind farm's estimated annual production is 1.1 terawatt hours (TWh) and it will provide power for approximately 220,000 households.

Hywind

The Hywind demonstration facility off the coast of Karmøy in Norway - featuring the world's first full-scale floating offshore wind turbine - has been in operation for four years. The overall performance of Hywind has exceeded expectations. A project has now been initiated to investigate the possibility of installing a 30 MW test farm in Scotland. In October 2012, Statoil signed an agreement with Hitachi Zosen for a feasibility study of the use of Hywind technology off the coast of Japan.

Dudgeon (offshore wind project)

Statoil acquired a 70% shareholding in the Dudgeon wind farm project in October 2012 together with Statkraft (30%). This project is located in the Greater Wash Area off the English east coast, not far from Sheringham Shoal. The project has obtained the consent of the UK authorities allowing for up to 560 MW of installed generation capacity. Engineering studies are currently being undertaken to optimise the development concept. The wind farm is expected to have a production of 1.75 TWh from approximately 60 - 70 turbines providing power for approximately 330,000 households. Pending a final investment decision, it could be fully operational by year end 2017.

Dogger Bank

Statoil was awarded a 25% share in the UK Third Round Dogger Bank concession in 2010 together with partners Rheinisch-Westfalische Elektrizitatswerke (RWE), Scottish and Southern Energy (SSE) and Statkraft. The joint venture (Forewind) is currently undertaking environmental studies and preparing applications for consent to build offshore wind farms. The applications for the first two projects (each 1.2 GW) have been confirmed by the UK authorities to be sufficiently matured, and a final decision is expected in late 2014. Work on the remaining applications continues. Production could start towards the end of the decade.

Carbon capture and Storage (CCS)
The Norwegian government has decided to halt the development of the full scale carbon capture plant at Mongstad (CCM). CCS remains an important issue for Statoil, and Statoil will continue to engage in technology development through TCM (Technical Centre Mongstad). Statoil is currently involved in a process to develop a roadmap on further CCS involvement.

3.8 Other Group

The Other reporting segment includes activities in Global Strategy and Business Development (GSB); Technology, Projects and Drilling (TPD); and Corporate staffs and support functions.

3.8.1 Global Strategy and Business Development (GSB)

Global Strategy and Business Development (GSB) brings together Statoil's corporate strategy, business development and merger, acquisition and divestment activities to actively drive corporate development.

GSB sets the strategic direction for Statoil and identifies, develops and delivers business opportunities. This is achieved through close collaboration across geographic locations and business areas. Statoil's strategy plays an important role in guiding Statoil's business development focus.

GSB's business activities are organised in the following areas:
- **Corporate mergers and acquisitions**: responsible for initiating and executing corporate merger, acquisition and divestment processes.
- **Corporate strategy and analysis:** responsible for the corporate strategy development processes, competitor intelligence, industry analysis and the running of Statoil's Strategy Advisory Council.
- **Business development execution**: responsible for business development project execution, technical evaluation and commercial analysis.

From 2 April 2013, the corporate functions Political Analysis and Corporate Sustainability joined GSB.

Political analysis is responsible for monitoring political developments nationally, regionally and globally. The unit assesses political risk related to specific countries and projects, changes to the broader security threat picture, and geopolitical issues and trends impacting our business.

Corporate sustainability is responsible for setting out Statoil's strategic response to sustainability issues, the development of relevant policies and for reporting on the company's sustainability performance.

3.8.2 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.

In 2013, TPD had approximately 7,100 employees (internal & external) located in 28 countries supporting Statoil operations. Our total deliveries related to drilling and well activities and projects amounted to approximately NOK 120 billion.

Key events in 2013:
- Completed 120 offshore wells, including 13 international and 25 NCS exploration wells
- Delivered six new fast-track projects: Hyme, Vigdis, Skuld, Stjerne, Visund North and Vilje South
- Two drilling rigs acquired that will be owned by the licence partners of Gullfaks and Oseberg Area. These rigs will contribute to increased recovery and extended field life. This rig intake is part of Statoil's long-term rig-category strategy to rejuvenate its rig fleet, secure long-term rig capacity and reduce drilling costs to improve NCS recovery rates
- Overall 70 technology implementations have been completed in Statoil, including first-use and re-use of technologies. 64 technologies qualified for first use and six technologies proven for re-use

The TPD's business activities are organised in the following business clusters:

Research, Development and Innovation
The Research, Development and Innovation business cluster (RDI) is responsible for carrying out research to meet Statoil's business needs.

RDI is organised in four programmes: Unconventionals, Frontier developments, Mature area developments & IOR, and Exploration. They cover the main upstream building blocks where Statoil is growing. The RDI organisation operates and further develops laboratories and large-scale test facilities, and it has an academic programme that coordinates cooperation with universities and research institutes. Statoil has four research centres in Norway, a heavy oil technology centre in Canada and representatives in offices in Beijing (China), Rio de Janeiro (Brazil), Houston (US) and St. John's (Canada), close to many of our international operations.

Technology Excellence
The Technology Excellence business cluster (TEX) is responsible for delivering technical expertise to projects, business developments and assets globally, and for new technology and the corporate technology strategy.

TEX's technological expertise in areas such as petroleum technology, subsea and marine technology, facilities and operations technology, and HSE, enhances Statoil's operational performance. Technology development and implementation are used to promote and achieve corporate targets for production growth, increased regularity, reserve growth and increased recovery, reduced costs and improved drilling efficiency. TEX drives the initiative to increase the level of standardisation. TEX also supports innovators and entrepreneurs in connection with technology development and commercialisation activities.

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

The project portfolio comprises around 80 projects in the early phase and 70 in the execution phase. The project portfolio is diverse, ranging from major new field developments to both small and large redevelopment projects on the Norwegian continental shelf (NCS) and internationally. However, the share of larger projects in the portfolio has increased over the last few years.

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

D&W operated 44 rig years in 2013 compared to 42 in 2012, and delivered production and exploration wells offshore on the NCS and exploration wells in Canada, Gulf of Mexico, Tanzania and Mozambique.

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

The procurement process is based on competition and the principles of openness, non-discrimination and equality. We encourage and facilitate collaboration with our 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. We have a strategy for increasing diversity, competition and flexibility in the markets in which we operate in order to better utilise industry capacity and expertise.

3.8.3 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, CFO office, legal services and people and organisation.

3.9 Significant subsidiaries

The following table shows significant subsidiaries and associated companies as of 31 December 2013.

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

Ownership in certain subsidiaries and other equity accounted companies (in %)

Name	%	Country of incorporation	Name	%	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 2013, 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 the sections *Business overview - Development and Production Norway* and *Business overview - 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 the section *Business overview - 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 condensate and an immaterial quantity of bitumen are included in oil production. NGL includes both LPG and naphtha. For further information on production volumes, please see the section *Financial review - Operating and financial review - Definition of reported volumes.*

Entitlement production	For the year ended 31 December 2013	2012	2011
Norway			
Oil and NGL (mmbbls)	216	231	252
Natural gas (bcf)	1,264	1,483	1,287
Combined oil and gas (mmboe)	441	495	481
Eurasia excluding Norway			
Oil and NGL (mmbbls)	15	17	15
Natural gas (bcf)	72	62	48
Combined oil and gas (mmboe)	28	28	23
Africa			
Oil and NGL (mmbbls)	59	56	46
Natural gas (bcf)	40	41	40
Combined oil and gas (mmboe)	66	63	53
Americas			
Oil and NGL (mmbbls)	54	50	31
Natural gas (bcf)	196	161	59
Combined oil and gas (mmboe)	89	79	41
Total			
Oil and NGL (mmbbls)	345	353	343
Natural gas (bcf)	1,571	1,748	1,434
Combined oil and gas (mmboe)	625	665	598

3.10.2 Production costs and sales prices

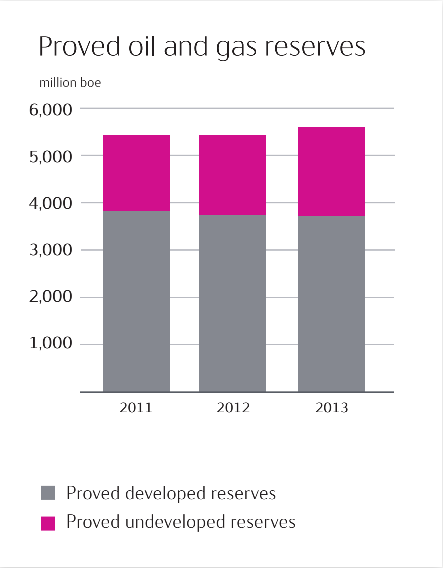
The following tables present the average unit of production cost based on entitlement volumes and realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 2013				
Average sales price liquids in USD per bbl	101.0	110.5	106.6	85.7
Average sales price natural gas in NOK per Sm3	2.4	0.9	2.1	0.8
Average production cost in NOK per boe	50	49	59	46
Year ended 31 December 2012				
Average sales price liquids in USD per bbl	104.5	113.1	109.1	88.2
Average sales price natural gas in NOK per Sm3	2.5	1.0	2.3	0.6
Average production cost in NOK per boe	45	47	59	58
Year ended 31 December 2011				
Average sales price liquids in USD per bbl	105.6	111.7	108.2	97.6
Average sales price natural gas in NOK per Sm3	2.2	1.0	1.9	0.9
Average production cost in NOK per boe	45	52	54	80

3.11 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,600 mmboe at year end 2013, compared to 5,422 mmboe at the end of 2012.

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 *Critical accounting judgements and key sources of estimation uncertainty; Key sources of estimation uncertainty; 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)* to the Consolidated financial statements.



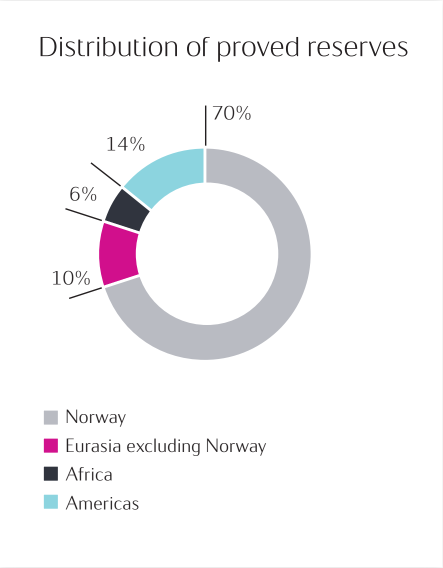
Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of development projects. These are 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. While higher oil and gas prices normally allow more oil and gas to be recovered from the accumulations, Statoil will generally receive smaller quantities of oil and gas under production-sharing agreements (PSAs) and similar contracts. 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, 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 Norway, 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.

Approximately 83% of Statoil's 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 (USA), the United Kingdom (UK), Canada and Ireland.



Of Statoil's total proved reserves, 14% are related to production-sharing agreements (PSAs) in non-OECD countries such as Angola, Algeria, Nigeria and Libya in Africa, Azerbaijan 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 additions to proved reserves in 2013 were:

- Positive revisions due to better performance of producing fields, maturing of improved recovery projects, and reduced uncertainty due to further drilling and production experience. This added a total of 395 million boe in 2013.
- Proved reserves from new discoveries have also been added through the sanctioning of nine new field development projects in 2013 such as the Shah Deniz phase 2 development in Azerbaijan and Aasta Hansteen in Norway in addition several other projects in Norway, US and Angola. Sanctioning of new projects added a total of 457 million boe.
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the USA increased the proved reserves in 2013, and some of these additions are presented as extensions. Extensions added a total of 66 million boe of new proved reserves in 2013.
- The net effect of the OMV and Wintershall transactions in addition to the sale of acreage onshore US reduced the proved reserves by 116 billion boe in 2013.

The 2013 entitlement production was 625 million boe, a decrease of 6% compared to 2012. New discoveries with proved reserves booked in 2013 are all expected to start production within a period of five years.

Summary of proved oil and gas reserves as of 31 December 2013

Reserves category	Oil and NGL (mmbbls)	Proved reserves Natural Gas (bcf)	Total oil and gas (mmboe)
Developed			
Norway	834	11,580	2,898
Eurasia excluding Norway	63	467	146
Africa	206	209	244
Americas	278	817	424
Total Developed proved reserves	1,382	13,073	3,711
Undeveloped			
Norway	451	3,181	1,018
Eurasia excluding Norway	164	1,455	423
Africa	81	120	103
Americas	240	586	344
Total Undeveloped proved reserves	936	5,343	1,888
Total proved reserves	2,318	18,416	5,600

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 2013, 2012 and 2011.

(million boe)	For the year ended 31 December 2013	2012	2011
Revisions and improved recovery	**395**	353	373
Extensions and discoveries	**523**	378	232
Purchase of petroleum-in-place	**14**	4	161
Sales of petroleum-in-place	**(131)**	(74)	(66)
Total reserve additions	**802**	661	700
Production	**(625)**	(665)	(598)
Net change in proved reserves	**177**	(4)	101

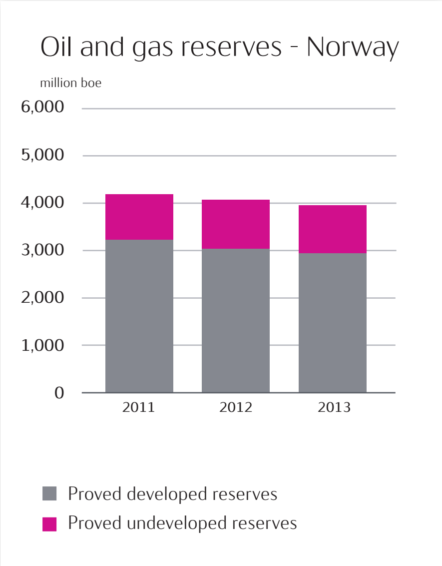
The reserves replacement ratio for 2013 was 1.28 compared to 0.99 in 2012. The 2013 reserves replacement ratio, excluding purchases and sales of petroleum in place, was 1.47. The average replacement ratio for the last three years was 1.15, or 1.19 excluding purchases and sales.

Reserves replacement ratio (including purchases and sales)	For the year ended 31 December 2013	2011	2010
Annual	**1.28**	0.99	1.17
Three-year-average	**1.15**	1.01	0.92

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 3,916 million boe is recognised as proved reserves in 61 fields and field development projects on the Norwegian continental shelf (NCS), representing 70% of Statoil's total proved reserves. Of these, 53 fields and field areas are currently in production, 42 of which are operated by Statoil. Five new field development projects sanctioned during 2013, Aasta Hansteen, Oseberg Delta 2, Gudrun Øst, Rhea and Fram H Nord, have added new proved reserves 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 2013.



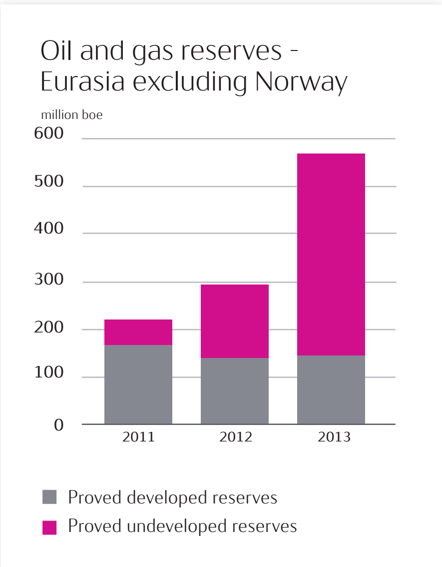
Sales of reserves are mainly related to the agreements with Wintershall and OMV to sell interests in certain licences in Norway. This has reduced Statoil's share of proved reserves on Gjøa, Vega, Gudrun and the Gullfaks area and removed Brage and Brage Sognefjord from the proved reserves accounts.

The Ormen Lange redetermination has reduced Statoil's share of proved reserves in this field and is included as a negative revision.

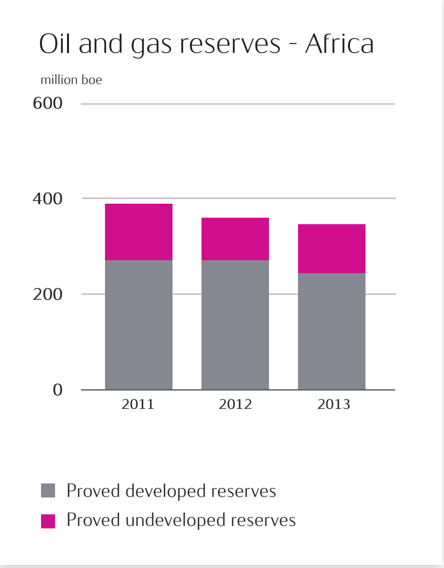
Of the proved reserves on the NCS, 2,898 million boe, or 74%, are proved developed reserves. Of the total proved reserves, 67% are gas reserves related to large offshore gas fields such as Troll, Snøhvit, Oseberg, Aasta Hansteen, Ormen Lange, Tyrihans, Åsgard and Visund, and 33% are oil reserves.

Proved reserves in Eurasia, excluding Norway

In this area, Statoil has proved reserves of 569 million boe related to seven fields and field developments in Azerbaijan, the United Kingdom (UK), Ireland and Russia. Eurasia excluding Norway represents 10% of Statoil's total proved reserves, Azerbaijan being the main contributor with the Shah Deniz and Azeri-Chirag-Gunashli fields. All fields are producing, except for the Corrib field in Ireland, which is still under development and anticipated to start production in 2015, and the Mariner field in the UK, which is expected to start production in 2017. As part of the OMV deal, Schiehallion in the UK was sold and is therefore removed from the proved reserves account. Shah Deniz stage 2, was sanctioned during 2013 and have added new proved reserves categorised as extensions and discoveries. The effect of the reduced equity share in Shah Deniz will be included in 2014, after the closing date of the transaction, and will reduce the proved reserves at year end 2014.



Of the proved reserves in Eurasia, 146 million boe or 26% are proved developed reserves. Of the total proved reserves in this area, 40% are oil reserves and 60% are gas reserves.



Proved reserves in Africa

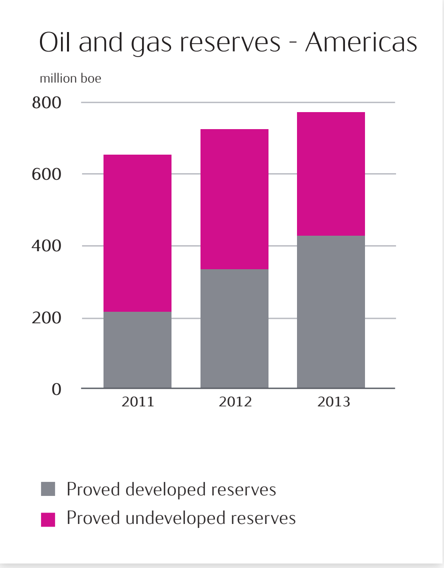
Statoil recognises proved reserves of 346 million boe related to 25 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 6% of Statoil's total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 20 of the 25 fields.

All fields are in production in Algeria, Libya and Nigeria.

In Angola, Statoil has proved reserves in four blocks, Block 4, Block 15, Block 17 and Block 31, with production from all blocks. Four discoveries in Block 17, called the CLOV project, and some of the Kizomba satellites in Block 15 are still under development.

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, 244 million boe, or 70%, are proved developed reserves. Of the total proved reserves in this area, 83% are oil reserves and 17% are gas reserves.



Proved reserves in the Americas

In North and South America, Statoil has proved reserves equal to 768 million boe in a total of 16 fields and field development projects. This represents 14% of Statoil's total proved reserves. Nine of these fields are located in the United States (USA), six 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. The sanctioning of Heidelberg added new reserves in the Gulf of Mexico in 2013. The Spiderman field stopped producing late 2013 and has no longer proved reserves.

In the USA, two of the six fields in the Gulf of Mexico are in production. Field development is ongoing on Big Foot, Jack, Heidelberg and St. Malo. The onshore tight reservoir assets Marcellus, Eagle Ford and Bakken are all in production. Further drilling in these assets has increased the proved reserves in 2013, which are expressed as extensions and revision of previous estimate.

In Canada, proved reserves are related both to offshore field developments, and to the Leismer Demonstration Project in the KKD oil sands project in Alberta. The effect of the agreement between Statoil and PTTEP, to divide their respective interests in this project, will be included after the expected closing in 2014 and has not affected the 2013 proved reserves estimates.

Of the total proved reserves in the Americas, 424 million boe, or 55%, are proved developed reserves. Of the total proved reserves in this area, 67% are oil reserves and 33% gas reserves.

3.11.1 Development of reserves

In 2013, approximately 460 million boe were converted from undeveloped to developed proved reserves.

The start-up of production from the Hyme, Skarv, Skuld and Stjerne in Norway increased developed reserves by 116 million boe during 2013. The rest of the converted volume is related to development activities on producing fields.

The sanctioning of new development projects in Norway, Azerbaijan, US and Angola, added a total of 457 million boe of proved undeveloped reserves in 2013.

		Oil and NGL (mmbbls)	Natural gas (bcf)	Total (mmboe)
2013	**Proved reserves end of year**	**2,318**	**18,416**	**5,600**
	Developed	1,382	13,073	3,711
	Undeveloped	936	5,343	1,888
2012	**Proved reserves end of year**	**2,389**	**17,027**	**5,422**
	Developed	1,383	13,210	3,737
	Undeveloped	1,006	3,817	1,686
2011	**Proved reserves end of year**	**2,276**	**17,681**	**5,426**
	Developed	1,381	13,730	3,827
	Undeveloped	895	3,951	1,599

As of 31 December 2013, the total proved undeveloped oil and gas reserves amounted to 1,888 million boe, 54% of which are related to fields in Norway. The Snøhvit, Troll and Kvitebjørn, Visund and Grane fields, which have continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Aasta Hansteen, Gina Krogh, Gudrun, Ivar Aasen and Goliat. The largest assets with respect to undeveloped proved reserves outside Norway are Shah Deniz in Azerbaijan, Mariner and Corrib in the UK, the US onshore developments in Bakken, Marcellus and Eagle Ford and CLOV in Angola.

In 2013, Statoil incurred NOK 98 billion in development costs relating to assets carrying proved reserves, NOK 75 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 Ekofisk, Heidrun, Oseberg, Snorre, Snøhvit and Troll in Norway, Azeri-Chirag-Gunashli and Shah Deniz in Azerbaijan, Hebron and Leismer in Canada, Mariner in the UK and Petrocedeño in Venezuela. 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.

The Corrib gas development in Ireland (operated by Shell), has been under development for more than five years. Most of the offshore and onshore facilities are in place and the field is expected to start production in 2015.

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 28 years' experience in the oil and gas industry, 27 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 2013. 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 2013	Oil, Condensate and LPG (mmbbls)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,318	18,416	5,600
Estimated by DeGolyer and MacNaughton	2,295	19,249	5,724

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.

Productive oil and gas wells and developed and undeveloped acreage
The following tables show the number of gross and net productive oil and gas wells, and total gross and net developed and undeveloped oil and gas acreage, in which Statoil had interests at 31 December 2013.

A gross value reflects wells or acreage in which we have 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 2013		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells						
Oil wells	— gross	906	135	417	2,117	3,575
	— net	326.3	19.9	61.2	1,285.4	1,692.7
Gas wells	— gross	207	11	78	1,387	1,683
	— net	86.2	3.0	29.5	329.8	448.5

The total gross number of productive wells as of end 2013 includes 464 oil wells and 28 gas wells with multiple completions or wells with more than one branch.

At 31 December 2013 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	Americas	Australia	Total
Developed and undeveloped oil and gas acreage							
Acreage developed	— gross	871	90	1,026	805	-	2,793
	— net	315	20	306	556	-	1,197
Acreage undeveloped	— gross	11,045	21,987	20,717	15,208	22,422	91,379
	— net	4,164	8,545	6,747	6,746	18,182	44,384

The largest concentrations of developed acreage in Norway are in the Troll, 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 Australia, which was acquired in 2013. Indonesia has the largest undeveloped acreage in Eurasia excluding Norway, with 57% of the total for this geographic area. The largest acreage concentration in Africa is in Angola, representing 59% of the total net acreage in Africa.

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	Total
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	0.0	0.0	0.0	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	0.0	0.7	1.3	3.7
— Net productive development wells drilled	24.9	2.3	5.3	320.6	353.1
Year 2012					
Net productive and dry exploratory wells drilled	8.7	2.0	3.0	3.1	16.8
— Net dry exploratory wells drilled	2.3	2.0	0.4	1.6	6.3
— Net productive exploratory wells drilled	6.4	0.0	2.6	1.5	10.5
Net productive and dry development wells drilled	22.8	1.9	7.0	441.0	472.6
— Net dry development wells drilled	1.3	0.0	0.3	0.6	2.1
— Net productive development wells drilled	21.5	1.9	6.7	440.4	470.5
Year 2011					
Net productive and dry exploratory wells drilled	14.5	0.7	1.9	6.6	23.6
— Net dry exploratory wells drilled	4.8	0.4	0.8	2.7	8.7
— Net productive exploratory wells drilled	9.7	0.3	1.1	3.9	14.9
Net productive and dry development wells drilled	20.8	2.0	10.6	144.8	178.1
— Net dry development wells drilled	1.0	0.0	0.8	0.6	2.4
— Net productive development wells drilled	19.8	2.0	9.8	144.2	175.7

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 2013.

At 31 December 2013		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of wells in progress						
Development Wells	— gross	33	3	29	451	516
	— net	13.3	0.9	5.7	149.4	169.3
Exploratory Wells	— gross	4	-	1	1	6
	— net	6.8	0.8	2.1	3.1	12.7

3.11.4 Delivery commitments

This section describes the long-term NCS commitments for the contract years 2013-2016.

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 2013, the long-term commitments from NCS for the Statoil/SDFI arrangement totalled approximately 15.89 trillion cubic feet (tcf) (450 bcm).

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the gas years 2013, 2014, 2015 and 2016, are 1.59, 1.64, 1.64 and 1.58 tcf (45, 46.3, 46.4 and 44.8 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

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

The principal laws governing our petroleum activities in Norway and on the NCS are currently 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. We are dependent on the Norwegian State for approval of our NCS exploration and development projects and our applications for production rates for individual fields.

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 Ministry of Petroleum and Energy primarily implements petroleum policy through its powers to administer the awarding of licences and to approve operators' field and pipeline development plans. Only plans that comply with the policies and regulations adopted by the Storting are approved. As set out in the Petroleum Act, if a plan involves an important principle or will have a significant economic or social impact, it must also be submitted to the Storting for acceptance before being approved by the Norwegian Ministry of Petroleum and Energy.

We are not required to submit any decisions relating to our operations to the Storting. However, the Storting's role in relation to major policy issues in the petroleum sector can affect us in two ways: firstly, when the Norwegian State acts in its capacity as majority owner of our 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 we issue 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. It is not possible to predict what stance the Norwegian Storting will take on a proposal to issue additional shares that would either significantly dilute its holding of Statoil shares or require a capital contribution from it in excess of government mandates. A decision by the Norwegian State to vote against a proposal on our part to issue additional shares would prevent us from raising additional capital in this manner and could adversely affect our ability to pursue business opportunities. For more information about the Norwegian State's ownership, see the sections *Risk review - Risk factors - Risks related to state ownership* and *Shareholder information - Major shareholders*.
- The Norwegian State exercises important regulatory powers over us, as well as over other companies and corporations. As part of our business, we, or the partnerships to which we are 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 our or 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.

Although Norway is not a member of the European Union (EU), it 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 us is adopted in the EU and then applied to Norway under the EEA Agreement. As a Norwegian company operating both within EFTA and the EU, our business activities are subject to both the EFTA Convention governing intra-EFTA trade and EU laws and regulations adopted pursuant to the EEA Agreement.

3.12.1 The Norwegian licensing system

Production licences are the most important type of licence awarded under the Petroleum Act, and the Norwegian Ministry of Petroleum and Energy has executive discretionary powers to award and set the terms for production licences.

As a participant in licences, we are subject to the Norwegian licensing system. For an overview of our activities and shares in our production licences, see *Business overview - Development and Production Norway (DPN).*

Production licences are the most important type of licence awarded under the Petroleum Act, and the Ministry of Petroleum and Energy has executive discretionary powers to award a production licence and to decide the terms of that licence. The Norwegian Government is not entitled to award us a licence in an area until the Norwegian parliament (Storting) has decided to open the area in question for exploration. The terms of our 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 normally awarded in licensing rounds. The first licensing round for NCS production licences was announced in 1965. The award of the first licences covered areas in the North Sea. Over the years, the awarding of licences has moved northward to cover areas in both the Norwegian Sea and the Barents Sea. In recent years, the principal licensing rounds have largely concerned licences in the Norwegian Sea. However, in the future, we expect an increase in licensing rounds for licences in the Barents Sea.

The Norwegian State accepts licence applications from individual companies and group applications. This allows us to choose our exploration and development partners, however the Ministry of Petroleum and Energy has full discretion with respect to which companies to award a licence and as such disregard a group application.

Production licences are awarded to joint ventures. 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. Once a production licence is awarded, the licensees are required to enter into a joint operating agreement and an accounting agreement regulating the relationship between the partners. 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.

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, under which the operator can normally terminate its engagement by giving six months' notice. The management committee can terminate the operator's engagement by giving six months' notice through an affirmative vote by all members of the management committee other than the operator. 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.

Production licences 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 production licence, 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. As a rule, the right to prolong a licence does not apply to the whole of the geographical area covered by the initial licence. The size of the area that must be relinquished is determined at the time the licence is awarded. In special cases, the Ministry of Petroleum and Energy may extend the duration of a production licence.

If natural resources other than petroleum are discovered in the area covered by a production licence, the Norwegian State may decide to delay petroleum production in the area. If such a delay is imposed, the licensees are, with certain exceptions, entitled to a corresponding extension of the licence period. To date, such a delay has never been imposed.

If important public interests are at stake, the Norwegian State may instruct us 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.

Licensees may buy or sell interests in production licences 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. The Ministry of Petroleum and Energy must also approve indirect transfers of interests in a licence, including changes in the ownership of a licensee, if they result in a third party obtaining a decisive influence over the licensee. 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.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. When applying for such licences a group of companies must prepare a plan for installation and operation. Licences for the establishment of facilities for the transportation and utilisation of petroleum will normally be awarded subject to certain conditions. Typically, these conditions require the facility owners to enter into a participants' agreement. 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. The decommissioning plan must be submitted to the Ministry of Petroleum and Energy no sooner than five years and no later than two years prior to the expiry of the licence or cessation of use of the facility, and it must include a proposal for the disposal of facilities on the field. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

The Norwegian State is entitled to take over the fixed facilities of the licensees when a production licence expires, is relinquished or revoked. In respect of facilities on the NCS, the Norwegian State decides whether any compensation will be payable for facilities thus taken over. If the Norwegian State should choose to take over onshore facilities, the ordinary rules of compensation in connection with the expropriation of private property apply.

Licences for the establishment of facilities for the transportation and utilisation of petroleum typically include a clause whereby the Norwegian State can require that the facilities be transferred to it free of charge on expiry of the licence period.

3.12.2 Gas sales and transportation

We market gas from the NCS on our 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 our and the Norwegian State's gas produced on the NCS is sold under long-term 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 *Business overview - Marketing, Processing and Renewable Energy (MPR) - Natural Gas - The Norwegian gas transportation system*.

3.12.3 HSE regulation

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

Norway
Under the Petroleum Act of 29 November 1996, our 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.

On 10 June 2013 the EU adopted a directive on safety of offshore oil and gas operations. All member states will have to abide by the directive. The directive is not considered to be comprised by the European Economic Area (EEA), of which Norway is part and will thus not have implication to our NCS activities.

We are 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.

See also *Risk review - Risk factors - Legal and regulatory risks.*

Global operations
With business operations in 35 countries and territories, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. 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 our operations in the USA. 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 *Risk review - Risk factors - Legal and regulatory risks.*

3.12.4 Taxation of Statoil

We are subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to our offshore activities in Norway. Internationally, our activities are mainly subject to tax in the countries where we operate.

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. The holders of production licences are also required to pay an area fee. The amount of the area fee is stipulated in regulations issued under the Petroleum Act.

Corporate income tax
Our 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 was 28% in 2013. From 2014 it has been reduced to 27%. Our 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 and the value of lifted stocks of oil are determined on the basis of norm prices. Norm prices are decided on a daily basis by the Petroleum Price Board, a body whose members are appointed by the Norwegian Ministry of Petroleum and Energy. Norm prices are 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. When stipulating norm prices, the Petroleum Price Board takes a number of factors into consideration, including spot market prices and contract prices in the industry.

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 tax values 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 28% income tax rate (27% as of 1 January 2014). Losses on foreign activities cannot be deducted from NCS income. Losses on offshore activities are fully deductible from onshore income.

By using group contributions between Norwegian companies in which we hold 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 our offshore income.

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividend received, which is subject to the standard 28% income tax rate (27% as of 1 January 2014). 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 28% income tax rate (27% as of 1 January 2014) 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 28% income tax rate (27% as of 1 January 2014) 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 was in 2013 levied at a rate of 50%. From 2014 it is increased to 51%. The special tax is applied to relevant income in addition to the standard income tax rate, resulting in a 78% marginal tax rate on income subject to 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, and a tax-free allowance, or uplift, is granted at a rate of 7.5% per year for investments made prior to 5 May 2013. For investments made from 5 May 2013 the rate is 5.5% per year. Transitional rules apply to investments 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 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.

Taxation outside Norway

Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of our 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. Parties to a PSA are generally insulated, via the terms of the PSA, against legislative changes in a country's general tax laws.

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.

3.12.5 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 we also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

3.12.6 SDFI oil and gas marketing and sale

We market and sell the Norwegian State's oil and gas as part of our own production. The Norwegian State has chosen to implement this arrangement.

Accordingly, at an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised our articles of association by adding a new article that requires us to continue to market and sell the Norwegian State's oil and gas together with our own oil and gas. This is done in accordance with an instruction established in shareholder resolutions in effect from time to time. At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instruction referred to in the new article. 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 to Statoil. It contains a general requirement that, in our activities on the NCS, we must take account of these ownership interests in decisions that could affect the execution of this marketing arrangement.

The Owner's instruction sets out specific terms for the marketing and sale of the Norwegian State's oil and gas. 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 our 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. In addition, the following considerations are important:

- to create the basis for long-term and predictable decisions concerning the marketing and sale of the Norwegian State's oil and gas;
- to ensure that results, including costs and revenues related to our oil and gas and the Norwegian State's oil and gas, are transparent and measurable; and
- to ensure efficient and simple administration and execution.

Our tasks
Our 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. In the event that the owner's instruction is terminated in whole or in part by the Norwegian State, the owner's instruction provides for a mechanism under which contracts for the marketing and sale of the Norwegian State's oil and gas to which we are party may be assigned to the Norwegian State or its nominee. Alternatively, the Norwegian State may require that the contracts be continued in our name, but that, in the underlying relationship between the Norwegian State and us, the Norwegian State has all rights and obligations relating to the Norwegian State's oil and gas.

Costs
The Norwegian State does not pay us a specific consideration for performing these tasks, but reimburses us for its proportionate share of certain costs, which, under the owner's instruction, may be our 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 us and to third parties, is based either on the prices achieved, a net back formula or market value. We purchase 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 our own natural gas volumes, a list has been established for deciding the 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.

3.13 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. The office buildings are wholly owned by Statoil.

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 takes out insurance policies for physical loss of or damage to our oil and gas properties, liability to third parties, workers' compensation and employer's liability, general liability, pollution and well control, among other things.

Our insurance policies are subject to:
- Deductibles, excesses and self-insured retentions (SIR) that must be borne prior to recovery.
- Exclusions and limitations.

Our well control policy, which covers costs relating to well control incidents (including pollution and clean-up costs), is subject to a gross limit per incident. The gross limits for our two most significant geographical areas, the NCS and the Gulf of Mexico (GoM), USA, are:

NCS
- NOK 11,500 million per incident for exploration wells.
- NOK 2,000 million per incident for production wells.

GoM
- USD 1,800 million (approximately NOK 10,800 million) per incident for exploration wells.
- USD 300 million (approximately NOK 1,800 million) per incident for production wells.

The limits assume a 100% ownership interest in a given well and would be scaled to be equivalent to our percentage ownership interest in a given well. Our SIR for well control policies would be NOK 200 million per incident on the NCS assuming 100% ownership. Our SIR in the GoM would be approximately USD 10 million (approximately NOK 60 million) per incident assuming 100% ownership. 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 (approximately NOK 4,800 million) per incident. The SIR is insignificant (maximum NOK 6 million).

We have a variety of other insurance policies related to other projects worldwide for which we have limited SIR.

There is no guarantee that our insurance policies will adequately protect us against liability for all potential consequences or damages.

3.16 People and the group

3.16.1 Employees in Statoil

The Statoil group employs approximately 23,400 employees. Of these, approximately 20,300 are employed in Norway and approximately 3,100 outside Norway.

Numbers of permanent employees and percentage of women in the Statoil group from 2011 to 2013

	Number of employees*			Women*		
Geographical Region	2013	2012	2011	2013	2012	2011
Norway	**20,336**	20,186	20,021	**30%**	30%	31%
Rest of Europe	**935**	925	10,187	**30%**	30%	50%
Africa	**140**	116	121	**33%**	25%	28%
Asia	**140**	157	146	**53%**	56%	59%
North America	**1,559**	1,378	1,030	**35%**	34%	34%
South America	**303**	266	210	**38%**	38%	40%
TOTAL	**23,413**	23,028	31,715	**31%**	31%	37%
Non - OECD	**690**	653	2,773	**39%**	39%	64%

* Statoil Fuel and Retail employees are included in 2011.

Total workforce by region, employment type and new hires in the Statoil group in 2013

Geographical Region	Permanent employees	Consultants	Total Workforce*	Consultants (%)	Part time (%)	New hires
Norway	20,336	1,826	22,162	8%	3%	923
Rest of Europe	935	145	1,080	13%	2%	72
Africa	140	30	170	18%	NA	34
Asia	140	11	151	7%	NA	26
North America	1,559	7	1,566	0.4%	NA	303
South America	303	103	406	25%	NA	56
TOTAL	23,413	2,122	25,535	8%	3%	1,414
Non - OECD	690	146	836	17%	NA	119

* The total workforce consists of permanent employees and consultants. Enterprise personnel are not included in the figures. Enterprise personnel are defined as third-party service providers and work on our onshore and offshore operations. These were roughly estimated to be around 46,000 in 2013.

Statoil works systematically and implements recruitment and development programmes aimed at building a diverse workforce by attracting, recruiting and retaining people of both genders and different nationalities and age groups across all types of positions. In 2013, Statoil recruited 1,414 new employees worldwide. While 65% were recruited to jobs in Norway, 21% were recruited to our business in North America, reflecting our growth ambitions in that region.

We believe Statoil's low turnover rates reflect a high level of satisfaction and engagement among its employees, which is also supported by the results of the annual organisational and working environment survey. In Statoil, the total turnover rate for 2013 was 3.7%.

3.16.2 Equal opportunities

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

Statoil recognises the value of diversity throughout the organisation and in 2013 we have continued to monitor and promote diversity in our global workforce. We believe that diversity generates new and different ways of thinking and is crucial for our successful and sustainable international growth. We continue to focus on increasing the number of women in leadership and professional positions and building broad international experience in our workforce.

In 2013, the overall percentage of women in the company was 31% - and 50% of the members of the board of directors were women, as were 11% of the corporate executive committee. We pay close attention to male-dominated positions and discipline areas, and in 2013 the proportion of female engineers increased by 1% to 27% in Statoil ASA. Among staff engineers with up to 20 years' experience, the proportion of women was 30%.

In 2013 the total proportion of female managers in Statoil remained stable at 27%. We continue to strive to increase the number of female managers through our development programmes.

The reward system in Statoil is non-discriminatory and supports equal opportunities, which means that, given the same position, experience and performance, men and women will be at the same salary level. However, due to differences between women and men in types of positions and number of years' experience, there are some differences in compensation when comparing the general pay levels of men and women.

Cultural diversity
Statoil believes that being a global and sustainable company requires people with a global mindset. One way to build a global company is to ensure that recruitment processes both within and outside Norway contribute to a culturally diverse workforce. In 2013, 34% of our new hires were women and 48% nationalities other than Norwegian.

Outside Norway, we need to continue to focus on increasing the number of people and managers that are locally recruited and to reduce the long-term, extensive use of expats in our business operations. In 2013, 21% of employees and 22% of the managerial staff in the Statoil group held nationalities other than Norwegian.

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, 66% 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 five Statoil unions.

In 2013, management and employee representatives collaborated closely, in particular on the follow-up of the In Amenas terrorist attack, safety incidents on the Norwegian continental shelf and the review of Statoil's staff and service functions. In addition, the European Works Council continued to be an important channel of communication between the company and employees.

4 Financial review

4.1 Operating and financial review

The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

4.1.1 Sales volumes

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

In addition to our 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 the section *Business overview - Applicable laws and regulations - SDFI oil & gas marketing & 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 segment MPR, natural gas volumes sold by the segment DPI and ethane volumes.

For more information on the differences between equity and entitlement production, sales volumes and lifted volumes, see the section *Financial review - Operating and financial review - Definitions of reported volumes*.

Sales Volumes	For the year ended 31 December 2013	2012	2011
Statoil: [1]			
Crude oil (mmbbls) [2]	350	351	332
Natural gas (bcf)	1,622	1,721	1,377
Combined oil and gas (mmboe)	639	658	577
Third party volumes: [3]			
Crude oil (mmbbls) [2]	303	399	333
Natural gas (bcf)	431	210	244
Combined oil and gas (mmboe)	380	436	376
SDFI assets owned by the Norwegian State:			
Crude oil (mmbbls) [2]	155	156	162
Natural gas (bcf)	1,366	1,591	1,476
Combined oil and gas (mmboe)	398	439	425
Total:			
Crude oil (mmbbls) [2]	809	905	827
Natural gas (bcf)	3,419	3,523	3,096
Combined oil and gas (mmboe)	1,418	1,533	1,379

(1) 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. Changes in inventory may cause these volumes to differ from the sales volumes reported elsewhere in this report by MPR in that these volumes include volumes still in inventory or transit held by other reporting entities within the group. Excluded from such volumes are volumes lifted by DPI but not sold by the MPR, and volumes lifted by DPN or DPI and still in inventory or in transit.

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

(3) 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.

4.1.2 Group profit and loss analysis

Net operating income was NOK 155.5 billion in 2013, down 25% compared to 2012, impacted by reduced production, lower prices measured in NOK, higher operating expenses and lower fair value of derivatives. Increased impairment losses and provisions related to onerous contracts and a redetermination process, added to the decrease and were only partly offset by higher gains from sales of assets.

The Financial Supervisory Authority (FSA) of Norway has conducted a review of our 2012 financial statements. Statoil has evaluated the impact of the conclusions from the review to be immaterial under IAS 8 for the financial statements for 2013 and prior years. Consequently, no restatement of prior years' comparative amounts has been performed in the 2013 financial statements. See note 28 *Subsequent events* to the Consolidated financial statements for more information.

Operational review

	For the year ended 31 December				
Operational data	2013	2012	2011	13-12 change	12-11 change
Average liquids price (USD/bbl)	**100.0**	103.5	105.6	(3%)	(2%)
USDNOK average daily exchange rate	**5.88**	5.82	5.61	1%	4%
USDNOK period-end exchange rate	**6.08**	5.57	5.61	9%	(1%)
Average liquids price (NOK/bbl)	**588**	602	592	(2%)	2%
Average invoiced gas prices (NOK/scm)	**2.01**	2.19	2.08	(8%)	5%
Refining reference margin (USD/bbl)	**4.1**	5.5	2.3	(25%)	>100%
Production (mboe per day)					
Entitlement liquids production	**964**	966	945	(0%)	2%
Entitlement gas production	**792**	839	706	(6%)	19%
Total entitlement liquids and gas production	**1,756**	1,805	1,650	(3%)	9%
Total entitlement liquids and gas production - net of US royalties	**1,719**	1,778	1,643	(3%)	8%
Equity liquids production	**1,115**	1,137	1,118	(2%)	2%
Equity gas production	**825**	867	732	(5%)	18%
Total equity liquids and gas production	**1,940**	2,004	1,850	(3%)	8%
Liftings (mboe per day)					
Liquids liftings	**950**	959	910	(1%)	5%
Gas liftings	**792**	839	706	(6%)	19%
Total liquids and gas liftings	**1,742**	1,797	1,616	(3%)	11%
Production cost (NOK/boe, last 12 months)					
Production cost entitlement volumes	**50**	48	48	5%	(0%)
Production cost equity volumes	**44**	42	42	5%	(0%)

Total equity liquids and gas production (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 1,940 mboe, 2,004 mboe and 1,850 mboe per day in 2013, 2012 and 2011, respectively.

The 3% decrease in total equity production in 2013 compared to 2012 was primarily due to expected natural decline on mature fields, divestments and redeterminations and decreased gas deliveries from the NCS. The decrease was partly offset by start-up and ramp-up of production on various fields.

The 8% increase in total equity production in 2012 compared to 2011 was primarily due to increased gas deliveries from the NCS, start-up of production from new fields and ramp-up of production on various fields. Higher maintenance activities in 2011 partly accounts for the lower production in 2011. Expected natural decline on mature fields and the Heidrun redetermination settlement with a relatively high production in 2011, partly offset the increase in equity production.

Total entitlement liquids and gas production - net of US royalties (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 1,719 mboe per day in 2013, compared to 1,778 mboe per day in 2012 and 1,643 mboe per day in 2011. The 3% decrease from 2012 to 2013 was impacted by the decrease in equity production as described above, and a relatively lower negative effect from Production Sharing Agreements

(PSA effect). The 8% increase from 2011 to 2012 was impacted by the increase in equity production as described above and a relatively lower negative PSA effect. The PSA effect was 182 mboe, 199 mboe and 200 mboe per day in 2013, 2012 and 2011, 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 *Financial review - Operating and financial review - Definition of reported* volumes for more information.

Production cost per boe of entitlement volumes was NOK 50, NOK 48 and NOK 48 for the 12 months ended 31 December 2013, 2012 and 2011, respectively. Based on equity volumes, the production cost per boe was NOK 44, NOK 42 and NOK 42 for the 12 months ended 31 December 2013, 2012 and 2011, respectively.

Production cost per boe of entitlement volumes and equity volumes are non-GAAP measures, see section *Non-GAAP measures - Financial review - Unit of production cost* for further information.

Exploration expenditures (including capitalised exploration expenditures) was NOK 21.8 billion in 2013, compared to NOK 20.9 billion in 2012 and NOK 18.8 billion in 2011. The NOK 0.9 billion increase in 2013 stem mainly from higher drilling activity on the NCS and increased field development costs, and were only partly offset by lower seismic expenditures and lower drilling activity internationally. The NOK 2.1 billion increase in 2012 stem mainly from both higher drilling activity and increased field evaluation expenditures, partly offset by lower activity on the NCS.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Revenues	**619.4**	704.3	645.4	(12%)	9%
Net income from associated companies	**0.1**	1.7	1.3	(92%)	32%
Other income	**17.8**	16.0	23.3	11%	(31%)
Total revenues and other income	**637.4**	722.0	670.0	(12%)	8%
Purchases [net of inventory variation]	**(307.5)**	(364.5)	(320.1)	(16%)	14%
Operating expenses and selling, general and administrative expenses	**(84.1)**	(72.3)	(72.9)	16%	(1%)
Depreciation, amortisation and net impairment losses	**(72.4)**	(60.5)	(51.4)	20%	18%
Exploration expenses	**(18.0)**	(18.1)	(13.8)	(1%)	31%
Net operating income	**155.5**	206.6	211.8	(25%)	(2%)
Net financial items	**(17.0)**	0.1	2.0	>(100%)	(95%)
Income before tax	**138.4**	206.7	213.8	(33%)	(3%)
Income tax	**(99.2)**	(137.2)	(135.4)	(28%)	1%
Net income	**39.2**	69.5	78.4	(44%)	(11%)

Total revenues and other income amounted to NOK 637.4 billion in 2013 compared to NOK 722.0 billion in 2012 and NOK 670.0 billion in 2011. 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 12% decrease in revenues from 2012 to 2013 was mainly attributable to reduced volumes of liquids and gas sold. Lower liquids and gas prices measured in NOK, lower unrealised gains on derivatives and the drop in revenues due to the divestment of the Fuel and Retail segment in the second quarter of 2012, added to the decrease. Increased volumes of third party gas sold, partly offset the decrease in revenues.

The 8% increase in revenues from 2011 to 2012 was mainly attributable to increased volumes of liquids and gas sold and higher prices measured in NOK for both liquids and gas. Lower unrealised gains on derivatives and the drop in revenues caused by the divestment of the Fuel and Retail segment in the second quarter of 2012 partly offset the increase in revenues.

Other income was NOK 17.8 billion in 2013 compared to NOK 16.0 billion in 2012 and NOK 23.3 billion in 2011. The NOK 1.8 billion increase from 2012 to 2013 stem mainly from higher gains from divestments, mainly related to the sales of assets to OMV and Wintershall in 2013.

The decrease in other income from 2011 to 2012 stems mainly from the relatively higher gain from sale of assets in 2011, mainly related to the divestments of Peregrino, the Kai Kos Dehseh oil sands and Gassled in 2011.

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 *Business overview - Applicable laws and regulations- SDFI oil and gas marketing and sale* for more details.

Purchases [net of inventory variation] amounted to NOK 307.5 billion in 2013, compared to NOK 364.5 billion in 2012 and NOK 320.1 billion in 2011. The 16% decrease from 2012 to 2013 was mainly related to lower SDFI volumes purchased and lower liquids and gas prices. The drop in purchases as a result of the divestment of the Fuel and Retail segment in second quarter of 2012, added to the decrease. Increased volumes of third party gas purchased, partly offset the decrease. The 14% increase from 2011 to 2012 was mainly caused by increased volumes and higher prices of liquids purchased, measured in NOK.

Operating expenses and selling, general and administrative expenses amounted to NOK 84.1 billion, up 16% compared to 2012, mainly due to increased operating plant cost from start-up and ramp-up of production on various fields, higher royalty expenses, and an onerous contract provision. In addition, a reclassification of diluent cost from purchases to operating expenses in the first quarter of 2013 added to the increase. Reversal of a provision related to the discontinued part of the early retirement pension, recorded in 2012, also contributed to the increase.

In 2012, operating expenses and selling, general and administrative expenses amounted to NOK 72.3 billion, down 1% compared to 2011. Higher operating plant costs from start-up and ramp-up of production on various fields, higher transportation activity due to higher volumes of liquids and longer distances and increased transportation costs due to lower Gassled ownership share, added to the increase. This was offset by the reversal of a provision in the second quarter 2012 related to the discontinued part of the early retirement pension and the drop in expenses caused by the divestment of the Fuel and Retail segment in the second quarter of 2012.

Depreciation, amortisation and net impairment losses amounted to NOK 72.4 billion in 2013 compared to NOK 60.5 billion in 2012 and NOK 51.4 billion in 2011. Included in these totals were net impairment losses of NOK 7.0 billion for 2013, NOK 1.3 billion for 2012 and NOK 2.0 billion for 2011.

Depreciation, amortisation and net impairment losses increased by 20% compared to 2012 due to higher impairment losses related to refineries and certain other assets, start-up on new fields with higher depreciation cost per unit, ramp-up of production from various fields and higher investments on producing fields. The increase was partly offset by reduced depreciation due to the lower production volumes, increased reserve estimates, divestments and redeterminations.

Depreciation, amortisation and net impairment losses increased by 18% in 2012 compared to 2011 mainly because of higher depreciation due to start-up and acquisition of new fields. Ramp-up and higher entitlement production on various fields together with higher investments added to the increase. Higher reserve estimates and lower ownership share in Gassled partly offset the increase.

Exploration expenses (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Exploration expenditures (activity)	21.8	20.9	18.8	4%	11%
Expensed, previously capitalised exploration expenditures	1.9	2.7	1.8	(30%)	49%
Capitalised share of current period's exploration activity	(6.9)	(5.9)	(6.4)	16%	(8%)
Impairments, net of reversal	1.2	0.4	(0.3)	>100%	>(100%)
Exploration expenses	18.0	18.1	13.8	(1%)	31%

In 2013, **exploration expenses** were NOK 18.0 billion, a NOK 0.1 billion decrease since 2012, when exploration expenses were NOK 18.1 billion. Exploration expenses were NOK 13.8 billion in 2011.

The 1% decrease in exploration expenses was mainly due to a higher portion of exploration expenditures being capitalised due to commercial wells in 2013, a lower portion of exploration expenditures capitalised in previous periods being expensed in 2013 and lower spending on seismic. Increased drilling activity and field development costs and a higher portion of exploration expenditures capitalised in previous periods being impaired, partly offset the decrease.

Exploration expenses increased by 31% in 2012 compared to 2011, mainly due to higher drilling activity in the international business, increased spending on seismic and field evaluation and a lower portion of exploration expenditures being capitalised in 2012 due to non-commercial wells. A higher portion of exploration expenditures capitalised in previous periods being expensed in 2012, added to the increase.

As a result of the above, **net operating income** was NOK 155.5 billion in 2013, compared to NOK 206.6 billion in 2012 and NOK 211.8 billion in 2011.

Net financial items amounted to a loss of NOK 17.0 billion in 2013, compared to a gain of NOK 0.1 billion in 2012. The decrease was mainly due to negative changes in currency derivatives used for currency and liquidity risk management as a result of changes in underlying currency positions together with a strengthening of USD towards NOK of 9.3% in 2013 compared to a weakening of USD towards NOK of 7.1% in 2012. In addition a negative fair value change on interest rate swap positions relating to the interest rate management of non-current bonds due to an increase in long term USD interest rates by an average of 1.0% in 2013 compared to a decrease in 2012 by an average of 0.2%. This was offset by increased interest income and other financial items mainly due to reduced impairment loss related to financial investment as well as decreased interest and other finance expenses.

Net financial items amounted to a gain of NOK 0.1 billion in 2012, compared to a gain of NOK 2.0 billion in 2011. The decrease was mainly due to an impairment loss related to a financial investment in 2012.

Income taxes were NOK 99.2 billion in 2013, equivalent to an effective tax rate of 71.7%, compared to NOK 137.2 billion in 2012, equivalent to an effective tax rate of 66.4%, and NOK 135.4 billion in 2011, equivalent to an effective tax rate of 63.3%.

The increase in the effective tax rate from 2012 to 2013 was mainly due to higher impairment losses, onerous contract provisions and increased losses on financial items, all with lower than average tax rates. This was partly offset by increased capital gains with lower than average tax rates and relatively lower income from the NCS in 2013. Income from the NCS is subject to a higher than average tax rate.

The increase in the effective tax rate from 2011 to 2012 was mainly due to a one-off deferred tax expense related to a tax law change in Norway and relatively higher income from the NCS in 2012 compared to 2011. Income from the NCS is subject to a higher than average tax rate. The tax rate in both 2012 and 2011 was decreased due to recognition of previously unrecognised deferred tax assets.

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 28% (27% from 2014), and income in other countries is taxed at the applicable income tax rates in those countries.

In 2013, the **non-controlling interest** in net profit was negative NOK 0.6 billion, compared to positive NOK 0.6 billion in 2012 and negative NOK 0.4 billion in 2011. The non-controlling interest was primarily related to the ownership share in Mongstad crude oil refinery, being 79% throughout 2013. After acquiring the remaining 21% from Shell, transaction effective 1 January 2014, Statoil is the 100% owner of the Mongstad refinery.

In 2013, **net income** was NOK 39.2 billion compared to NOK 69.5 billion in 2012 and NOK 78.4 billion in 2011. The 44% decrease from 2012 to 2013 was mainly due to the decrease in net operating income, increased loss on net financial items and the increase in the effective tax rate as described above.

The 11% decrease from 2011 to 2012 was mainly due to the decrease in net operating income and the increase in the effective tax rate as described above.

The board of directors will propose for approval at the annual general meeting an **ordinary dividend** of NOK 7.00 per share for 2013, an aggregate total of NOK 22.3 billion. In 2012, the ordinary dividend was NOK 6.75 per share, an aggregate total of NOK 21.5 billion. In 2011, the ordinary dividend was NOK 6.50 per share, an aggregate total of NOK 20.7 billion.

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 MPR and SFR (until 19 June 2012 when SFR was sold). According to the acquisition agreement, sale of refined oil products to SFR will continue for a specific period of time. Sales of fuel from the MPR segment to SFR are presented as external sales in the MPR segment as of 20 June 2012.

DPN produces oil and natural gas which is sold internally to MPR. A large share of the oil produced by DPI is also sold from MPR. 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 is reported net of royalty interest. This change does not result in a change in the net operating income. Historical information has been aligned to the current presentation, reflected in the following tables.

In 2013, the average transfer price for natural gas was NOK 1.92 per scm. The average transfer price was NOK 1.84 per scm in 2012 and NOK 1.64 in 2011. For oil sold from DPN to MPR, the transfer price is the applicable market-reflective price minus a cost recovery rate of NOK 0.71 per barrel.

The following table shows certain financial information for the five segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2013. For additional information please refer to note 3 *Segments* to the Consolidated financial statements.

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Development & Production Norway			
Total revenues and other income	202.2	220.8	212.1
Net operating income	137.1	161.7	152.7
Non-current segment assets*	247.6	235.4	211.6
Development & Production International			
Total revenues and other income	81.9	80.1	70.2
Net operating income	16.4	21.5	32.8
Non-current segment assets*	286.5	248.3	239.4
Marketing, Processing and Renewable Energy			
Total revenues and other income	611.4	669.5	610.0
Net operating income	2.6	15.5	24.7
Non-current segment assets*	39.3	38.5	34.5
Fuel & Retail**			
Total revenues and other income	-	41.6	73.7
Net operating income	-	6.9	1.9
Non-current segment assets*	-	0.0	10.8
Other			
Total revenues and other income	1.0	1.3	1.1
Net operating income	(1.1)	2.6	(0.3)
Non-current segment assets*	5.6	4.5	4.0
Eliminations***			
Total revenues and other income	(259.1)	(291.2)	(297.6)
Net operating income	0.4	(1.6)	(0.1)
Non-current segment assets*	-	-	-
Statoil group			
Total revenues and other income	637.4	722.0	670.0
Net operating income	155.5	206.6	211.8
Non-current segment assets*	578.9	526.7	500.3

* Deferred tax assets, pension assets, associated companies and non-current financial instruments are not allocated to segments.

** Amounts are for the period until 19 June 2012 and include gains from the sale of the FR segment.

*** 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.

2013 Total revenues by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	238.0	95.5	61.7	69.5	14.0	478.7
USA	62.9	13.5	2.5	10.9	4.7	94.6
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 associated companies)	321.5	113.2	64.5	118.9	19.1	637.2

2012 Total revenues by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	278.1	107.3	61.3	91.8	19.0	557.5
USA	67.6	6.7	2.6	21.9	7.2	106.0
Sweden	0.0	0.0	0.0	9.1	(0.3)	8.8
Denmark	0.0	0.0	0.0	18.1	0.1	18.2
Other	21.5	4.5	1.8	(0.0)	2.1	29.9
Total revenues (excluding net income (loss) from associated companies)	367.2	118.5	65.7	140.9	28.1	720.3

2011 Total revenues by geographic area (in NOK billion)	Crude oil	Gas	NGL	Refined products	Other	Total sales
Norway	269.5	87.7	58.8	62.4	38.1	516.4
USA	34.0	7.2	1.9	17.2	5.1	65.5
Sweden	0.0	0.0	0.0	17.7	5.0	22.7
Denmark	0.0	0.0	0.0	17.4	1.6	19.1
Other	11.6	3.9	1.6	14.0	14.0	45.1
Total revenues (excluding net income (loss) from associated companies)	315.0	98.9	62.3	128.8	63.8	668.7

4.1.4 DPN profit and loss analysis

DPN generated total revenues of NOK 202.2 billion in 2013 and its net operating income was NOK 137.1 billion. The average daily entitlement production was 591 mboe per day for liquids and 626 mboe per day for gas.

Operational review

Operational data	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Prices					
Liquids price (USD/bbl)	**101.0**	104.5	105.6	(3%)	(1%)
Liquids price (NOK/bbl)	**593.8**	608.5	592.3	(2%)	3%
Transfer price natural gas (NOK/scm)	**1.92**	1.84	1.64	4%	12%
Production (mboe per day)					
Entitlement liquids	**591**	624	693	(5%)	(10%)
Entitlement natural gas	**626**	710	624	(12%)	14%
Total entitlement liquids and gas production	**1,217**	1,335	1,316	(9%)	1%
Liftings (mboe per day)					
Liquids liftings	**589**	632	673	(7%)	(6%)
Gas liftings	**626**	710	624	(12%)	14%
Total liquids and gas liftings	**1,215**	1,343	1,297	(10%)	4%

The average daily production of liquids and gas (see the section *Financial review - Operating and financial review - Definition of reported volumes*) was 1,217 mboe, 1,335 mboe and 1,316 mboe per day in 2013, 2012 and 2011, respectively. The average daily production of liquids and gas decreased by 9% from 2012 to 2013. Lower gas sales, divestments, Ormen Lange redetermination and expected reductions due to natural decline on mature fields were partly offset by production ramp-up on the Skarv field and new production from fast track developments.

The average daily production of liquids and gas increased by 1% from 2011 to 2012. Increased production of natural gas, mainly due to higher gas off-take from Oseberg and Troll, was partly offset by decreased production of liquids, mainly related to the Heidrun redetermination settlement with relatively high production in 2011 and reduced ownership share at Kvitebjørn.

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 *Financial review - Operating and financial review - Definition of reported volumes* for more information.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Total revenues and other income	**202.2**	220.8	212.1	(8%)	4%
Operating expenses and selling, general and administrative expenses	**(27.4)**	(25.8)	(24.7)	6%	4%
Depreciation, amortisation and net impairment losses	**(32.2)**	(29.8)	(29.6)	8%	1%
Exploration expenses	**(5.5)**	(3.5)	(5.1)	54%	(31%)
Net operating income	**137.1**	161.7	152.7	(15%)	6%

Total revenues and other income were NOK 202.2 billion in 2013, NOK 220.8 billion in 2012 and NOK 212.1 billion in 2011.

A 12% decrease in the lifted volumes of gas from 2012 to 2013 accounted for NOK 9.3 billion of the decrease of revenues, and a 7% decrease in the lifted volumes of liquids accounted for NOK 10.0 billion of the decrease of revenues. A decrease of 3% in the average price in USD of sold liquids by DPN to MPR accounted for NOK 4.4 billion. The effects were partly offset by increased gas price in NOK of sold gas that positively impacted revenues by NOK 2.5 billion in 2013. A positive exchange rate deviation of NOK 1.2 billion due to a 1% increase in the USD/NOK average daily exchange rate in 2013 also had a positive impact on revenues.

A 14% increase in the lifted volumes of gas from 2011 to 2012 accounted for NOK 8.5 billion of the increase in revenues. Increased gas price in NOK of sold gas positively impacted revenues by NOK 6.3 billion in 2012, and a positive currency exchange rate deviation of NOK 5.2 billion due to a 4% increase in the USD/NOK average daily exchange rate in 2012 also had a positive impact on revenues. The effects were partly offset by a decrease of 6% in the lifted volumes of liquids, accounting for NOK 9.9 billion. A decrease of 1% in the average price in USD of sold liquids by DPN to MPR accounted for NOK 1.4 billion.

Operating expenses and selling, general and administrative expenses were NOK 27.4 billion in 2013, compared to NOK 25.8 billion in 2012 and NOK 24.7 billion in 2011. In 2013, expenses increased compared to 2012 mainly due to increased environmental tax expenses caused by increased CO_2 tax rate as of 1 January 2013, and new fields in production. This was partly offset by divestments, a redetermination and reduced cost levels at several fields. In 2012, expenses increased compared to 2011 mainly due to increased operating plant costs related to higher maintenance activity and well maintenance on some fields (especially Gullfaks and Åsgard).

Depreciation, amortisation and net impairment losses were NOK 32.2 billion in 2013, compared to NOK 29.8 billion in 2012 and NOK 29.6 billion in 2011. The increase in 2013 compared to 2012 was mainly due to new fields in production with higher depreciation cost per unit and increased investments on major producing fields. This was partly offset by reduced depreciation due to net decreased production, increased proved reserves, effect of reduced retirement obligations, divestments and a redetermination. The increase in 2012 compared to 2011 was mainly related to net increased production and increased removal/abandonment estimates, partly offset by decreased depreciation due to increased proved reserves and redetermination at Heidrun.

Exploration expenses were NOK 5.5 billion, NOK 3.5 billion and NOK 5.1 billion in 2013, 2012 and 2011, respectively. The increase from 2012 to 2013 was mainly due to higher drilling activity and field development work within Johan Sverdrup and Johan Castberg areas. This was partly offset by a higher portion of current exploration expenditures being capitalised and a lower portion of exploration expenditures capitalised in previous periods being expensed in this period. The decrease from 2011 to 2012 was mainly due to lower drilling activity, high seismic activity in 2011 and lower exploration expenditures capitalised in previous periods being expensed in this period.

Net operating income in 2013 was NOK 137.1 billion, compared to NOK 161.7 billion in 2012 and NOK 152.7 billion in 2011. The NOK 24.6 billion decrease in 2013 compared to 2012 was mainly due to decreased volumes of liquids and gas. The NOK 9.0 billion increase in 2012 compared to 2011 was mainly due to increased gas prices and lifted volumes of gas.

In 2013, lower fair value of derivatives (NOK 5.6 billion), changes in gas revenue (NOK 0.6 billion), an onerous contract provision (NOK 0.8 billion), other adjustments (NOK 0.7 billion), change in over/underlift position (NOK 0.4 billion) and impairment losses (NOK 0.4 billion) had a negative impact on net operating income. Gains from sales of assets (NOK 13.2 billion), mainly related to OMV and Wintershall, had a positive impact on net operating income.

In 2012, the gain related to a sale of NCS assets to Centrica (NOK 7.5 billion), reversal of provision related to the discontinued part of the early retirement pension (NOK 0.7 billion) and over/underlift position (NOK 0.8 billion) positively impacted net operating income. An unrealised loss on derivatives (NOK 1.5 billion), impairment on Glitne (NOK 0.6 billion) and other adjustments (NOK 0.1 billion) negatively impacted net operating income.

In 2011, an unrealised gain on derivatives (NOK 5.2 billion) and gain on sale of assets (NOK 0.1 billion) positively impacted net operating income. Over/underlift position (NOK 2.5 billion), a change in future settlement related to a sale of a licence share (NOK 0.4 billion) and an adjustment related to pension costs (NOK 0.2 billion) negatively impacted net operating income.

4.1.5 DPI profit and loss analysis

In 2013, DPI delivered 13% growth in entitlement production net of royalties, averaging 502 mboe per day.

In 2013, DPI generated total revenues and other income of NOK 81.9 billion and a net operating income of NOK 16.4 billion.

Operational review

Operational data	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Prices					
Liquids price (USD/bbl)	98.4	101.4	105.7	(3%)	(4%)
Liquids price (NOK/bbl)	578.2	590.3	592.8	(2%)	(0%)
Production (mboe per day)					
Entitlement liquids	373	342	252	9%	35%
Entitlement natural gas	166	128	82	30%	56%
Total entitlement liquids and gas production	539	470	334	15%	41%
Total entitlement liquids and gas production - net of US royalties	502	443	327	13%	36%
Total equity liquids and gas production	723	669	534	8%	25%
Liftings (mboe per day)					
Liquids liftings	361	326	237	11%	38%
Gas liftings	166	128	82	30%	56%
Total liquids and gas liftings	527	454	318	16%	43%

The average daily equity liquids and gas production (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 723 mboe in 2013, compared to 669 mboe in 2012 and 534 mboe in 2011. The increase of 8% from 2012 to 2013 was driven primarily by ramp-up of fields, including Marcellus (US), Eagle Ford (US), PSVM (Angola) and Bakken (US). The increase was partly offset by natural decline, primarily at mature fields in Angola, and the effect of the In Amenas incident.

The increase of 25% from 2011 to 2012 was driven primarily by start-up/ramp-up of fields, including Pazflor (Angola), Marcellus (US) and Peregrino (Brazil) and the acquisition of Bakken (US) in the fourth quarter of 2011. This was partly offset by natural decline at several fields.

The average daily entitlement production of liquids and gas - net of US royalties (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 502 mboe per day in 2013, compared to 443 mboe per day in 2012 and 327 mboe per day in 2011. Both the increases from 2012 to 2013 and from 2011 to 2012 were driven by increased equity production as described above and a relatively lower negative effect from production sharing agreements (PSA effect). The PSA effect was 182 mboe, 199 mboe and 200 mboe per day in 2013, 2012 and 2011, 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 *Financial review - Operating and financial review - Definition of reported volumes* for more information.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Total revenues and other income	81.9	80.1	70.2	2%	14%
Purchases [net of inventory variation]	(0.1)	(1.3)	(0.7)	(95%)	91%
Operating expense and selling, general and administrative expenses	(21.0)	(16.5)	(14.2)	28%	16%
Depreciation, amortisation and net impairment losses	(31.9)	(26.2)	(13.8)	22%	90%
Exploration expenses	(12.5)	(14.6)	(8.7)	(14%)	67%
Net operating income	16.4	21.5	32.8	(24%)	(35%)

DPI generated **total revenues and other income** of NOK 81.9 billion in 2013 compared to NOK 80.1 billion in 2012 and NOK 70.2 billion in 2011. The increase from 2012 to 2013 was mainly caused by an increase in lifted volumes, which increased revenues by NOK 7.5 billion. In addition, increased gains from sales of assets positively impacted revenues by NOK 2.7 billion. The increase was partly offset by provisions related to commercial disputes in 2013, which had a negative impact of NOK 4.6 billion, a decrease in realised liquids and gas prices (measured in NOK), which had a negative impact of NOK 1.6 billion, and also by lower operating profit from an associated company in Venezuela which is accounted for using the equity method.

The increase from 2011 to 2012 was mainly related to an increase in lifted volumes, which increased revenues by NOK 22.5 billion. In addition, gains from sales of assets of NOK 1.0 billion and net increase in other income positively impacted revenues. The increase was partly offset by a decrease in realised liquid and gas prices (measured in NOK), which had a negative impact of NOK 0.9 billion, and gains from sales of assets of NOK 14.2 billion in 2011.

Purchases [net of inventory variation] were NOK 0.1 billion in 2013, compared to NOK 1.3 billion in 2012 and NOK 0.7 billion in 2011. The decrease from 2012 to 2013 was mainly related to diluent purchases being presented as operating expenses and not as purchases from 2013. The increase from 2011 to 2012 was mainly related to diluent purchases for Leismer operations that started in January 2011.

Operating expenses and selling, general and administrative expenses were NOK 21.0 billion in 2013, compared to NOK 16.5 billion in 2012 and NOK 14.2 billion in 2011. The 28% increase from 2012 to 2013 was mainly due to higher expenses resulting from production ramp-up on several fields and higher royalty expenses. Further, operating expenses increased by NOK 1.5 billion as diluent expenses are presented as operating expenses and not as purchases from 2013. The 16% increase from 2011 to 2012 was mainly due to higher production and ramp-up on new fields, and higher royalty expenses.

Depreciation, amortisation and net impairment losses were NOK 31.9 billion in 2013, compared to NOK 26.2 billion in 2012 and NOK 13.8 billion in 2011. The 22% increase from 2012 to 2013 was mainly due to ramp-up of production from various fields (PSVM, Marcellus, Bakken, Eagle Ford and Kizomba Satellites). Impairments of NOK 2.1 billion in 2013 also contributed to the increase. The increases were partly offset by reduced depreciation from increased reserves, divestment of assets and the In Amenas incident. The 90% increase from 2011 to 2012 was mainly due to start-up and acquisition of new fields (Pazflor, Peregrino, Bakken, Kizomba Satellites and Caesar Tonga), which increased depreciation by approximately NOK 9.3 billion. Ramp-up and net increased entitlement production from other fields also increased depreciation.

Exploration expenses were NOK 12.5 billion in 2013, compared to NOK 14.6 billion in 2012 and NOK 8.7 billion in 2011. The decrease from 2012 to 2013 was mainly due to lower drilling and seismic activities as well as increased drilling success, which resulted in more discoveries this year compared to last year and thus increased capitalised exploration expenditures. Exploration expenses increased by NOK 5.9 billion from 2011 to 2012, primarily due to increased expenses of non-commercial wells and increased seismic and field evaluation costs.

Net operating income in 2013 was NOK 16.4 billion, compared to NOK 21.5 billion in 2012 and NOK 32.8 billion in 2011. From 2012 to 2013, increased lifted volumes had a positive impact of NOK 7.5 billion. This increase was more than offset primarily by higher depreciation and operating expenses. From 2011 to 2012, increased lifted volumes had a positive impact of NOK 22.5 billion. This increase was offset by increased expenses, primarily depreciation expenses which increased by NOK 12.4 billion. In addition, net operating income for 2011 was positively impacted by gains from sales of assets of NOK 14.2 billion.

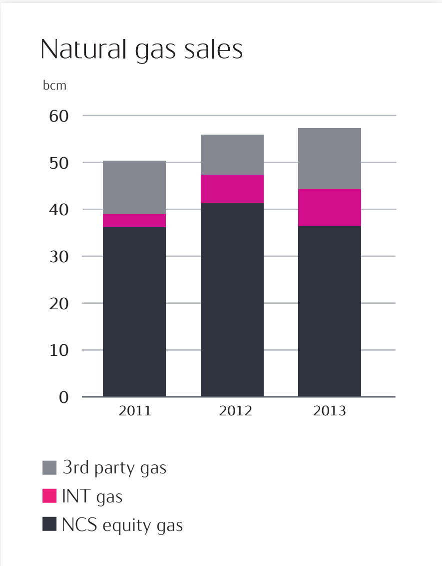
In 2013, net operating income was negatively impacted by provisions related to commercial disputes of NOK 4.6 billion, net impairment losses of NOK 3.2 billion (NOK 1.2 billion impacted the Exploration expenses line item), an adjustment related to tax oil barrels from previous periods of NOK 0.6 billion and changed over/underlift positions of NOK 0.2 billion. This was partly offset by gains on sales of assets of NOK 3.7 billion. In 2012, net operating income was positively impacted by gains on sales of assets of NOK 1.0 billion. In 2011, net operating income was positively impacted by NOK 14.2 billion from gains on sales of assets and net impairment reversals of NOK 2.4 billion. Over/underlift position of NOK 0.4 billion negatively impacted net operating income.

4.1.6 MPR profit and loss analysis

The 2013 results for MPR are highly influenced by an onerous contract provision and impairment losses on refineries, partly offset by high contribution from the gas activity in the US.

Operational review

Operational data	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Refining reference margin (USD/bbl)	4.1	5.5	2.3	(25%)	>100%
Crude oil sales volumes (mmbbl)	809	905	827	(11%)	9%
Natural gas sales Statoil entitlement (bcm)	44.2	47.3	39.0	(7%)	22%
Natural gas sales (third-party volumes) (bcm)	13.1	8.6	11.4	52%	(25%)
Average invoiced gas price (NOK/scm)	2.01	2.19	2.08	(8%)	5%
Transfer price natural gas (NOK/scm)	1.92	1.84	1.64	4%	12%

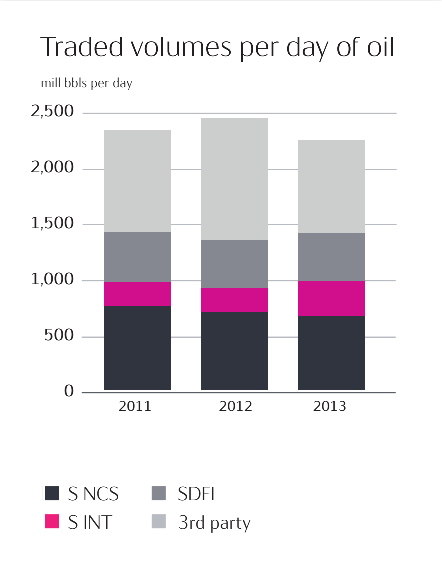


Total natural gas sales volumes were 57.3 bcm in 2013 (2.02 tcf), 55.9 bcm (1.97 tcf) in 2012 and 50.4 bcm (1.78 tcf) in 2011. The 2% increase in total gas volumes sold from 2012 to 2013 was related to higher third-party volumes. The 11% increase in gas volumes sold from 2011 to 2012 was mainly related to higher entitlement production.

Third party natural gas sales volumes, as presented in the table above do not include volumes sold on behalf of the Norwegian State's direct financial interest (SDFI). MPR sold 35.4 bcm, 39.9 bcm and 33.5 bcm of NCS gas on behalf of SDFI in 2013, 2012 and 2011, respectively.

In 2013, the average invoiced natural gas sales price was NOK 2.01 per scm, compared to NOK 2.19 per scm in 2012, a decrease of 8%. The decrease was mainly due to higher proportion of lower priced US volumes. The increase of 5% from 2011 to 2012 was due to an increase in gas prices linked to contracts for oil products as well as gas indexed prices, partly offset by higher US gas sales at significantly lower prices than in Europe.

All of Statoil's gas produced on the NCS is sold by MPR, purchased from DPN at a market-based internal price. Our average internal purchase price for gas was NOK 1.92 per scm in 2013, up from NOK 1.84 per scm in 2012. The increase of 4% from 2012 to 2013 was primarily due to higher market prices in 2013.

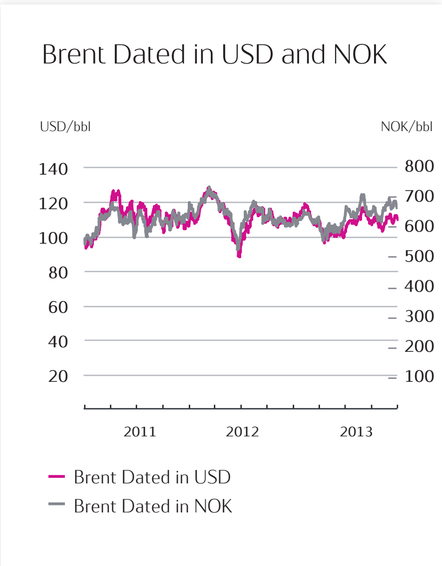


The average crude, condensate and NGL sales were 2.2 mmbbl per day in 2013. Of these daily sales, approximately 0.96 mmbbl are sales of our own volumes, 0.83 mmbbl are sales of third-party volumes and 0.42 mmbbl are volumes purchased from SDFI. Our average sales volume was 2.4 mmbbl per day in 2012 and 2.3 mmbbl per day in 2011. The average daily third-party volumes sold were 1.09 mmbbl in 2012 and 0.91 mmbbl in 2011.

The refinery margin had a negative development in 2013. The decrease was mainly driven by global competition and market oversupply in Europe. Statoil's refining reference margin was 4.1 USD/bbl in 2013, compared to 5.5 USD/bbl in 2012, a decrease of 25%. The refining reference margin was 2.3 USD/bbl in 2011.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Total revenues and other income	611.4	669.5	610.0	(9%)	10%
Purchases [net of inventory variation]	(565.8)	(620.3)	(550.5)	(9%)	13%
Operating expense and selling, general and administrative expenses	(36.0)	(30.6)	(28.8)	17%	6%
Depreciation, amortisation and net impairment losses	(7.0)	(3.0)	(6.0)	>100%	(50%)
Net operating income	2.6	15.5	24.7	(83%)	(37%)



Total revenues and other income were NOK 611.4 billion in 2013, compared to NOK 669.5 billion in 2012 and NOK 610.0 billion in 2011. The decrease in total revenues and other income from 2012 to 2013 was mainly due to lower gas and crude prices as well as lower volumes for crude and other oil products sold. These were partly offset by increased volumes of gas sold. The average crude price in USD declined by approximately 3% in 2013 compared to 2012, partly offset by a weakening of the USD/NOK average daily exchange rate by approximately 1% in 2013. The average invoiced sales price for gas decreased by 8%. The decrease was due to higher proportion of lower priced US volumes. Total natural gas sales volumes increased by 2%. Lower entitlement production on the NCS was more than offset by higher entitlement production in the US and higher third party volumes sold mainly in the US.

The increase from 2011 to 2012 was mainly due to higher prices and volumes for crude, other oil products and gas sold. The increase was partly offset by a gain related to the sale of the 24.1% interest in Gassled (NOK 8.4 billion) in 2011. The average crude price in USD increased by approximately 4% in 2012 compared to 2011, and the USD/NOK average daily exchange rate also increased by approximately 4%. The average invoiced sales price for gas increased by 5%. The increase was due to an increase in gas price for contracts linked to oil products as well as gas indexed prices, partly offset by a higher share of US gas sales at significantly lower prices than in Europe. Total natural gas sales volumes increased by 11%, mainly related to higher entitlement production, partly offset by decreased third-party volumes by 25%.

Purchases [net of inventory variation] were NOK 565.8 billion in 2013, compared to NOK 620.3 billion in 2012 and NOK 550.5 billion in 2011. The decrease from 2012 to 2013 was mainly due to lower crude price and lower crude and other oil products volumes sold partly offset by higher transfer price for natural gas from DPN. The increase from 2011 to 2012 was mainly due to higher prices and volumes for gas, crude and other oil products sold.

Operating expenses and selling, general and administration expenses were NOK 36.0 billion in 2013, compared to NOK 30.6 billion in 2012 and NOK 28.8 billion in 2011. The increase in expenses from 2012 to 2013 was mainly due to the Cove Point onerous contract provision (NOK 4.1 billion), increased operational activity and business development costs, partly offset by decreased transportation cost resulting from lower volumes of liquids sold in addition to cost reduction due to improvement initiatives. The increase in expenses from 2011 to 2012 was mainly triggered by increased transport activity due to higher volumes of liquids and longer distances (to capitalise on market opportunities) and increased external gas transportation cost as a result of lower Gassled ownership, partly offset by lower Gassled tariffs.

Depreciation, amortisation and net impairment losses were NOK 7.0 billion in 2013, compared to NOK 3.0 billion in 2012 and NOK 6.0 billion in 2011. The increase in depreciation, amortisation and net impairment losses from 2012 to 2013 was mainly caused by impairment losses related to the refineries (NOK 4.2 billion) and new assets in operation. The decrease in depreciation, amortisation and net impairment losses from 2011 to 2012 was mainly due to lower impairment losses related to refineries and other assets, lower depreciation driven by the Gassled divestment in 2011 and lower depreciation due to impairments made in 2011. The decrease was partly offset by reversal of an impairment loss in connection with Cove Point in 2011 and increased depreciation on new Mongstad refinery units.

Net operating income was NOK 2.6 billion, NOK 15.5 billion and NOK 24.7 billion in 2013, 2012 and 2011, respectively. The net operating income is further broken out below for MPR's major value chains **Natural Gas processing, marketing and trading** and **Crude oil processing, marketing and trading**.

Net operating income in **Natural Gas processing, marketing and trading** was NOK 5.0 billion, NOK 12.3 billion and NOK 27.5 billion in 2013, 2012 and 2011, respectively.

The decrease of NOK 7.3 billion from 2012 to 2013 was mainly due to an onerous contract provision in 2013 related to the Cove Point terminal (NOK 4.1 billion), reduced margins on gas sales, lower NCS entitlement production and lower contributions from short term sales.

The decrease in net operating income in Natural Gas processing, marketing and trading of NOK 15.2 billion from 2011 to 2012 was mainly due to the NOK 8.4 billion gain in 2011 related to the sale of the 24.1% interest in Gassled, and lower net operating income in 2012 due to Statoil's reduced ownership in Gassled. A negative change in fair value of derivatives (negative NOK 2.0 billion in 2012, compared to positive NOK 4.6 billion in 2011) and reversal in 2011 of provisions (NOK 1.6 billion) relating to an onerous contract accrued for in 2009 and 2010 also added to the decrease. The decrease was partly offset by higher margin from gas sales due to increased prices and volumes in addition to a higher contribution from trading and end user sales.

Net operating income in **Crude oil processing, marketing and trading** was a loss of NOK 2.1 billion, a gain of NOK 3.5 billion and a loss of NOK 2.4 billion in 2013, 2012 and 2011, respectively.

The decrease of NOK 5.6 billion from 2012 to 2013 was mainly due to impairment losses related to the refineries (NOK 4.2 billion), a negative change in fair value effects related to inventory hedging and lower refining margins in 2013 compared to in 2012. The basis for the impairment losses in 2013 is value in use estimates triggered by lower future expected refining margins.

The increase in Crude oil processing, marketing and trading of NOK 5.9 billion from 2011 to 2012 was mainly due to higher refinery margins and improved trading results in 2012 and impairment losses in 2011 related to our refinery assets (NOK 3.8 billion). The positive changes were partly offset by a negative change in fair value effects related to inventory hedging and a reduced gain on operational storage in 2012 compared to in 2011.

4.1.7 Other operations

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

In 2013, the Other reporting segment recorded a net operating loss of NOK 1.1 billion compared to a net operating income of NOK 2.6 billion in 2012 and a net operating loss of NOK 0.3 billion in 2011. The decrease in net operating income from 2012 to 2013 was mainly driven by a curtailment gain recognised in 2012 on the basis of Statoil's discontinuance of the supplementary (gratuity) part of the early retirement scheme. The increase in net operating income from 2011 to 2012 was driven by the same effect.

4.1.8 Definitions of reported volumes

This section explains some of the terms used when reporting volumes, such as lifted entitlement volumes, equity volumes, entitlement volumes and proved reserves.

Volumes that explain revenues

In explaining revenues and changes in revenues, we report **lifted entitlement volumes**. This is because we only recognise income from volumes to which we have legal title, and such title typically arises upon the lifting (i.e. loading onto a vessel) of the volumes. Under a production sharing agreement (PSA), we are only entitled to receive and sell certain parts of the volumes produced, and we therefore refer to entitlement volumes for revenue recognition purposes. The difference between equity and entitlement volumes is described in more detail below.

Volumes of lifted liquids (crude oil, condensate and natural gas liquids) and natural gas correlate with production over time, but they may be higher or lower than entitlement production for a given period due to operational factors that affect the timing of the lifting of the liquids from the fields by Statoil-chartered vessels. Volumes of natural gas produced on the Norwegian continental shelf (NCS) are deemed to be equal to lifted volumes of natural gas from the NCS.

Volumes of lifted liquids and natural gas may be sold or put into storage. The volumes that give rise to revenues from the sale of liquids and natural gas in the period are therefore equal to lifted volumes plus changes in inventories of liquids and natural gas.

Volumes that explain operating expenses

In explaining operating expenses, in total and in production cost per barrel of oil equivalents, we believe that **produced (equity) volumes** are a better indicator of activity levels than lifted volumes. Moreover, we believe that equity volumes are a better indicator of the activity level under PSAs than entitlement volumes, since our capital expenditure and operating expenses under such contracts are linked to equity volumes produced rather than to entitlement volumes received.

Equity volumes represent produced volumes that correspond to Statoil's percentage ownership interest in a particular field. **Entitlement volumes**, on the other hand, represent Statoil's share of the volumes distributed under a PSA 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. In some production sharing agreements, changes in prices or production rate can affect the contractors' share of production. Normally, a higher return on the project will lead to a higher government take. Consequently, a higher price may lead to lower entitlement production and entitlement reserves and vice versa. The distinction between equity and entitlement is relevant to most PSA regimes. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

As of fourth quarter 2013, entitlement production from the upstream segment in the US is presented net of royalties. Going forward, this will be the presentation format applied. Historical information is aligned with the current presentation to provide comparable figures.

Volumes of proved reserves

Proved reserves are based on estimated entitlement volumes recognised as reserves in accordance with the definitions of Rules 4-10 (a) of Regulation S-X and relevant guidance from the Securities and Exchange Commission (SEC) of the United States. They represent volumes that with reasonable certainty will be produced and to which we will have entitlement in the future. See the section *Business overview - Proved oil and gas reserves* and note *27 Supplementary oil and gas information (unaudited)* to the Consolidated financial statements, for details about how we measure and report proved reserves.

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 2013 reflect a high investment level, continued portfolio optimisation and issuance of new debt resulting in an increase in cash and cash equivalents and short-term financial investments.

Condensed cash flows statement (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Income before tax	138.4	206.7	213.8	(68.3)	(7.1)
Adjustments to reconcile net income to net cash flows provided by operating activities:					
Depreciation, amortisation and net impairment losses	72.4	60.5	51.4	11.9	9.1
Exploration expenditures written off	3.1	3.1	1.5	(0.0)	1.6
(Gains) losses on foreign currency transactions and balances	4.8	3.3	4.2	1.5	(0.9)
(Gains) losses on sales of assets and other items	(19.9)	(21.9)	(27.4)	2.0	5.5
(Increase) decrease in non-current items related to operating activities	8.8	(7.4)	(0.7)	16.2	(6.7)
(Increase) decrease in net derivative financial instruments	11.7	(1.1)	(12.8)	12.8	11.7
Interest received	2.1	2.6	2.7	(0.5)	(0.1)
Interest paid	(2.5)	(2.5)	(3.1)	(0.0)	0.6
Cash flows from (to) changes in working capital	(3.3)	4.6	1.9	(7.9)	2.7
Taxes paid	(114.2)	(119.9)	(112.6)	5.7	(7.4)
Cash flows provided by operating activities	101.3	128.0	119.0	(26.7)	9.0
Additions to PP&E and intangible assets	(113.3)	(111.2)	(91.4)	(2.1)	(19.9)
Additions through business combinations	0.0	0.0	(25.7)	0.0	25.7
(Increase) decrease in financial investments	(23.2)	(12.1)	3.8	(11.1)	(15.9)
Other changes	(1.1)	(3.1)	(1.5)	2.0	(1.7)
Proceeds from sales of assets and businesses	27.1	29.8	29.8	(2.7)	(0.0)
Cash flows used in investing activities	(110.4)	(96.6)	(84.9)	(13.8)	(11.8)
Net change in finance debt	55.5	0.9	2.7	54.6	(1.8)
Dividends paid	(21.5)	(20.7)	(19.9)	(0.8)	(0.8)
Net current loans and other	(7.3)	1.6	4.5	(8.9)	(2.9)
Cash flows provided by (used in) financing activities	26.6	(18.2)	(12.7)	44.8	(5.5)
Net increase (decrease) in cash and cash equivalents	17.5	13.2	21.4	4.3	(8.2)

Cash flows provided by operations

The most significant drivers of cash flows provided by operations are the level of production and prices for liquids and natural gas that impact revenues, purchases [net of inventory valuation], taxes paid and changes in working capital items. Cash flows provided by operations amounted to NOK 101.3 billion in 2013, a decrease of NOK 26.7 billion compared to 2012. The decrease was largely driven by decreased profitability mainly caused by lower volumes of liquids and gas sold and lower liquids and gas prices in 2013 compared to 2012. Changes in working capital had a negative impact of NOK 7.9 billion, partly offset by lower taxes paid of NOK 5.7 billion.

Cash flows provided by operations amounted to NOK 128.0 billion in 2012, compared to NOK 119.0 billion in 2011. The increase was largely driven by increased profitability mainly caused by increased volumes of liquids and gas sold and higher liquids and gas prices in 2012 compared to 2011. The increase was partly offset by higher taxes paid of NOK 7.4 billion and a greater negative impact from changes in non-current items related to operating activities of NOK 6.7 billion.

Cash flows used in investing activities
Cash flows used in investing activities increased by NOK 13.8 billion from 2012 to 2013. The increase was mainly due to higher additions to financial investments of NOK 11.1 billion. Proceeds from sales decreased by NOK 2.7 billion, and for the year ended 2013 the proceeds were mainly related to the sale of assets to OMV and Wintershall. For the year ended 2012, the proceeds from sales were mainly related to payments from the sale of interest in Gassled, the sale of NCS assets to Centrica and the sale of the 54% shareholding in Statoil Fuel and Retail ASA.

In 2012, cash flows used in investing activities amounted to NOK 96.6 billion, an increase of NOK 11.8 billion from 2011. The increase was mainly due to higher additions to PP&E and intangible assets of NOK 19.9 billion, which reflects a higher activity level in 2012 compared to 2011. Higher financial investments of NOK 15.9 billion also added to the increase. The increase was partly offset by the acquisition of Bakken assets in 2011, contributing NOK 25.7 billion.

Cash flows provided by (used in) financing activities
Net cash flows provided by financing activities amounted to NOK 26.6 billion in 2013, an increase of NOK 44.8 billion compared to 2012. The increase was mainly due to an increase in net finance debt of NOK 54.6 billion, partially offset by a decrease in current loans and other of NOK 8.9 billion.

Net cash flows used in financing activities amounted to NOK 18.2 billion in 2012, an increase of NOK 5.5 billion compared to 2011. The increase was mainly due to change in net finance debt of NOK 1.8 billion and change in current loans and other of NOK 2.9 billion, mainly due to increased repayment of loans.

4.2.2 Financial assets and debt

Statoil has a strong balance sheet and considerable financial flexibility. The net debt ratio before adjustments was 14.0% at the end of 2013. Net interest-bearing debt increased by NOK 18.7 billion to NOK 58.1 billion at the end of 2013.

Financial position and liquidity
Statoil's financial position is strong although net debt ratio before adjustments at year end increased from 10.9% in 2012 to 14.0% in 2013. Net interest-bearing debt increased from NOK 39.3 billion to NOK 58.1 billion. During 2013 Statoil's total equity increased from NOK 319.9 billion to NOK 356.0 billion. From 2012 to 2013 cash flows provided by operations are reduced and cash flows used in investments are increased. Statoil paid a dividend of NOK 6.75 per share for 2012, and the board of directors will propose a dividend of NOK 7.00 per share for 2013.

We believe that, given the current liquidity reserves, including committed credit facilities of USD 3.0 billion and very good access to various capital markets, Statoil will have sufficient capital available.

Funding needs arise as a result of the group's general business activity. The main rule is to establish financing at the corporate level. Project financing may be used in cases involving joint ventures with other companies. We aim at having 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 AA- from Moody's and S&P, respectively, both with stable outlook. 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. In this context, we carry out various risk assessments, some of them in line with financial matrices used by S&P and Moody's, such as funds from operations over net adjusted debt and net adjusted debt to capital employed.

The management of financial assets and liabilities takes into consideration funding sources, the maturity profile of non-current debt, interest rate risk management, currency risk and the management of liquid assets. Our borrowings are denominated in various currencies and mostly swapped into USD. In addition, we use interest rate derivatives, primarily consisting of interest rate swaps, to manage the interest rate risk of our long-term debt portfolio. The group's central treasury unit manages the funding, liability 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 2013, approximately 44% of our liquid assets were held in NOK-denominated assets, 33% in USD, 9% in DKK, 7% in SEK, 5% in EUR and 2% in GBP, before the effect of currency swaps and forward contracts. Approximately 54% of our liquid assets were held in treasury bills and commercial papers, 38% in time deposits, 5% in liquidity funds and 3% at bank available. As of 31 December 2013, approximately 1.5% 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 short-term 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 when market conditions are considered to be favourable.

The group's borrowing needs are usually covered through the issuing of short-term and long-term securities, including utilisation of a US Commercial Paper Program (program limit USD 4.0 billion) and a Shelf Registration Statement (unlimited) filed with the Securities and Exchange Commission (SEC) in the United States as well as through issues under a Euro Medium-Term Note (EMTN) Programme (program limit USD 12.0 billion) 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.

- Statoil ASA issued new debt securities in 2013 equivalent to NOK 62.8 billion as follows:

Issuance date	Amount	Interest rate	Maturity date
15 May 2013	USD 0.75 billion	1.15%	May 2018
15 May 2013	USD 0.50 billion	floating	May 2018
15 May 2013	USD 0.90 billion	2.65%	January 2024
15 May 2013	USD 0.85 billion	3.95%	May 2043
27 August 2013	USD 0.30 billion	floating	August 2020
10 September 2013	EUR 0.85 billion	2.00%	September 2020
10 September 2013	EUR 0.65 billion	2.88%	September 2025
10 September 2013	GBP 0.35 billion	4.25%	April 2041
16 September 2013	NOK 2.00 billion	4.13%	September 2025
16 September 2013	NOK 1.00 billion	4.27%	September 2033
8 November 2013	USD 0.75 billion	1.95%	November 2018
8 November 2013	USD 0.75 billion	floating	November 2018
8 November 2013	USD 0.75 billion	2.90%	November 2020
8 November 2013	USD 1.00 billion	3.70%	March 2024
8 November 2013	USD 0.75 billion	4.80%	November 2043
12 December 2013	EUR 0.15 billion	3.35%	December 2033

The new debt securities issued in 2013 were mainly issued under the US Shelf Registration Statement and the EMTN Programme. The NOK debt securities were registered in the Norwegian Securities Register (Verdipapirsentralen) and will be listed on the Oslo Stock Exchange. All of the new debt is guaranteed by Statoil Petroleum AS.

- Statoil ASA issued new debt securities in 2012 in the amounts of USD 0.6 billion maturing in January 2018, USD 1.1 billion maturing in January 2023 and reopened existing bonds maturing in November 2041 and issued USD 0.3 billion of bonds with the same maturity (an aggregate amount equivalent to NOK 11.6 billion). The registered bonds were issued under the US Shelf Registration Statement. All of the bonds are guaranteed by Statoil Petroleum AS.

Financial indicators

Financial indicators (in NOK billion)	For the year ended 31 December 2013	2012	2011
Gross interest-bearing debt [1]	**182.5**	119.4	131.5
Net interest-bearing debt before adjustments	**58.1**	39.3	71.0
Net debt to capital employed ratio [2]	**14.0%**	10.9%	19.9%
Net debt to capital employed ratio adjusted [3]	**15.2%**	12.4%	21.1%
Cash and cash equivalents	**85.3**	65.2	55.3
Current financial investments	**39.2**	14.9	5.1
Calculated ROACE based on Average Capital Employed before Adjustments [4]	**11.3%**	18.7%	22.1%
Ratio of earnings to fixed charges [5]	**7.5**	19.6	35.2

Gross interest-bearing debt

Gross interest-bearing debt was NOK 182.5 billion, NOK 119.4 billion and NOK 131.5 billion at 31 December 2013, 2012 and 2011, respectively. The NOK 63.1 billion increase from 2012 to 2013 was due to a decrease in current finance debt of NOK 1.3 billion and an increase in non-current finance debt of NOK 64.5 billion. Our weighted average annual interest rate was 4.06%, 4.74% and 4.84% at 31 December 2013, 2012 and 2011, respectively. Our weighted average maturity on Finance debt was 10 years at 31 December 2013, compared to 9 years at 31 December 2012 and 2011.

The NOK 12.1 billion decrease from 2011 to 2012 was due to a decrease in current finance debt of NOK 1.4 billion and non-current finance debt of NOK 10.7 billion.

Net interest-bearing debt

Net interest-bearing debt before adjustments were NOK 58.1 billion, NOK 39.3 billion and NOK 71.0 billion at 31 December 2013, 2012 and 2011, respectively. The increase of NOK 18.8 billion from 2012 to 2013 was mainly related to an increase in gross interest-bearing debt of NOK 63.1 billion in addition to an increase in cash and cash equivalents and current financial investments of NOK 44.4 billion, reflecting increased level of bond issues and active portfolio management (proceeds from sales of assets).

The net debt to capital employed ratio

The net debt to capital employed ratio before adjustments was 14.0%, 10.9% and 19.9% in 2013, 2012 and 2011, respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote 3) was 15.2%, 12.4% and 21.1% in 2013, 2012 and 2011, respectively. The 2.8 percentage points increase in net debt to capital employed ratio adjusted from 2012 to 2013 was mainly related to an increase in net interest-bearing debt adjusted of NOK 18.6 billion in combination with an increase in capital employed adjusted of NOK 54.7 billion. The 8.7 percentage points decrease in net debt to capital employed ratio adjusted from 2011 to 2012 was mainly related to a decrease in net interest-bearing debt adjusted of NOK 30.9 billion in combination with an increase in capital employed adjusted of NOK 3.8 billion.

Cash, cash equivalents and current financial investments

Cash and cash equivalents were NOK 85.3 billion, NOK 65.2 billion and NOK 55.3 billion at 31 December 2013, 2012 and 2011, respectively. The increase from 2012 to 2013 reflects the proceeds from sales of assets as well as increased level of bond issues. 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 39.2 billion, NOK 14.9 billion and NOK 5.2 billion at 31 December 2013, 2012 and 2011, respectively.

(1) Defined as non-current and current finance debt.
(2) As calculated according to GAAP. Net debt to capital employed ratio before adjustments is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and short-term investments. Capital employed is net debt, shareholders' equity and minority interest.
(3) In order to calculate the net debt to capital employed ratio adjusted that our management makes use of internally and which we report to the market, we make adjustments to capital employed as it would be reported under GAAP 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 GAAP. See report section Financial review - Non-GAAP measures for a reconciliation of capital employed and a description of why we make use of this measure.
(4) Calculated ROACE based on Average Capital Employed before Adjustments is equal to net income adjusted for financial items after tax, divided by average capital employed over the last 12 months. See report section Financial review - Non-GAAP measures for a reconciliation of ROACE and a description of why we make 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.

4.2.3 Investments

Organic capital expenditures (excluding acquisitions and financial leases) amounted to USD 19 billion for the year ended 31 December 2013, in line with our guidance for 2013 of around USD 19 billion.

Capital expenditures

Gross investments (in NOK billion)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Development & Production Norway	**57.3**	48.6	41.4	18%	17%
Development & Production International	**52.9**	54.6	84.4	(3%)	(35%)
Marketing, Processing & Renewable Energy	**5.9**	6.2	4.6	(5%)	34%
Fuel & Retail	**0.0**	0.9	1.5	(100%)	(41%)
Other	**1.3**	3.0	1.6	(58%)	85%
Gross investments	**117.4**	113.3	133.6	4%	(15%)

Gross investments, defined as additions to property, plant and equipment (including capitalised financial leases), capitalised exploration expenditures, intangible assets, long-term share investments and non-current loans granted, amounted to NOK 117.4 billion for the year ended 2013, increase by 4% compared to the year ended 2012. The increase was mainly due to higher activity level on the NCS.

In 2012, gross investments were NOK 113.3 billion compared to NOK 133.6 billion in 2011. The decrease was mainly due to gross investments related to the assets of Brigham Exploration Company in 2011, partly offset by increased gross investments in 2012 due to higher activity level compared to 2011.

Organic capital expenditures (excluding acquisitions and financial leases) amounted to NOK 114 billion for the year ended 2013, or USD 19 billion. This is in line with our guidance for 2013 of around USD 19 billion. Organic capital expenditures are estimated to be around USD 20 billion in 2014.

This section describes our estimated organic capital expenditure for 2014 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. For more information about the various projects in each of the segments, see the respective sub-sections described under the section *Financial review - Operating and financial review*.

We finance our capital expenditures both internally and externally. For more information, see the section *Financial review - Liquidity and capital resources - Financial assets and liabilities*.

A substantial proportion of our 2014 capital expenditures will be spent on ongoing and planned development projects in Norway such as Aasta Hansteen and Gina Krog in addition to various extensions, modifications and improvements on currently producing fields, like Gullfaks, Oseberg and Troll.

We currently estimate that a substantial proportion of our 2014 capital expenditure will be spent on the following ongoing and planned development projects internationally: CLOV in Angola, Mariner in UK, Shah Deniz in Azerbaijan, Marcellus, Eagle Ford and Bakken onshore US and developments offshore US.

We currently estimate that most of the 2014 capital expenditures spent on midstream and downstream projects will be related to Polarled, transport solutions for Marcellus Shale Gas and Eagle Ford in the US and on the NCS.

As illustrated in the section *Financial review - Liquidity and capital resources - Principal contractual obligations*, we have committed to certain investments in the future. The proportion of estimated investments that we have committed to at year-end 2013 will decline with time. 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.

Exploration expenditures

Exploration expenditures (including capitalised exploration expenditures) were up 4% to NOK 21.8 billion in 2013. Increased drilling activity and field development costs were only partly offset by lower seismic expenditures.

Exploration expenditures in 2012 amounted to NOK 20.9 billion, compared to NOK 18.8 billion in 2011. Exploration expenditures are estimated to be around USD 3.5 billion for 2014. The group expects to participate in the drilling of approximately 50 wells in 2014. However, no guarantees can be given with regard to the number of wells to be drilled, the cost per well and the results of drilling. Evaluation of the results of drilling will influence the amount of exploration expenditure capitalised and expensed. Refer to note 2 *Significant accounting policies* to the Consolidated financial statements.

Finally, we 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 inflation

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

As measured by the general consumer price index, average annual inflation in Norway for the year ending 31 December 2013 was 2%. Cost inflation 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. Although price pressure has abated since it peaked in 2008, similar to previous years, price increases were seen in the subsea and engineering segment in 2013. Stabilisation of raw material prices (e.g. steel) dampened the total increase in 2013.

While some of the cost pressure relates to capitalised expenditures and thus only affects our annual profit through increased depreciation, certain elements of operating expenditures have also been affected by this inflation. See our analysis of profit and loss in the section *Financial review - Operating and financial review* as well as the *Group outlook* section in the section *Strategy and market overview*.

4.2.5 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2013.

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 the section *Risk review - Risk management - Disclosures about market risk* for more information.

Contractual obligations (in NOK billion)	As at 31 December 2013 Payment due by period * Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current finance debt	16.0	29.4	41.0	160.6	246.9
Minimum operating lease payments	26.4	39.3	18.9	29.1	113.7
Nominal minimum other long-term commitments**	12.6	24.2	24.2	170.6	231.6
Total contractual obligations	55.0	92.8	84.1	360.4	592.2

* «Less than 1 year» represents 2014; «1-3 years» represents 2015 and 2016, «3-5 years» represents 2017 and 2018, while «More than 5 years» includes amounts for later periods.

** 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.

Contractual commitments relating to capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 70.2 billion as of 31 December 2013.

The group's projected pension benefit obligation was NOK 82.8 billion, and the fair value of plan assets amounted to NOK 65.8 billion as of 31 December 2013. Company contributions are mainly related to employees in Norway.

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 the section *Financial review - Liquidity and capital resources - Principal contractual obligations* and note 22 *Leases* to the Consolidated financial statements.

We are not party to any off-balance sheet arrangements such as the use of variable interest entities, derivative instruments that are indexed to our own shares and classified in shareholder's equity, or contingent assets transferred to an unconsolidated equity.

The group 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 judgments.

See note 28 *Subsequent events* to the Consolidated financial statements for information about a review of our 2012 financial statements conducted by the Financial Supervisory Authority of Norway.

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)
- Production cost per barrel of entitlement and equity volumes
- Net debt to capital employed ratio before adjustments
- Net debt to capital employed ratio adjusted

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 11.3% in 2013 compared to 18.7% in 2012 and 22.1% in 2011. The decrease from last year is due to 35% decrease in net income adjusted for financial items, combined with an increase in average capital employed. The decrease from 2011 to 2012 was due to the decrease in net income combined with 10% increase in capital employed.

Calculation of numerator and denominator used in ROACE calculation (in NOK billion, except percentages)	For the year ended 31 December 2013	2012	2011	13-12 change	12-11 change
Net Income for the year	39.2	69.5	78.4	(44%)	(11%)
Net Financial Items Adjusted for the year [1]	(4.6)	(2.3)	(8.2)	96%	(71%)
Calculated Tax on Financial Items for the year [2]	9.2	(0.1)	1.6	>(100%)	>(100%)
Net Income adjusted for Financial Items after Tax (A1)	43.9	67.0	71.9	(35%)	(7%)
Capital Employed before Adjustments to Net Interest-bearing Debt: [3]					
Year end 2013	414.0				
Year end 2012	359.2	359.2			
Year end 2011		356.1	356.1		
Year end 2010			295.9		
Sum of Capital Employed for two years (B1)	773.2	715.3	652.0		
Calculated Average Capital Employed:					
Average Capital Employed before Adjustments to Net Interest-bearing Debt (B1/2)	386.6	357.7	326.0	8%	10%
Calculated RoACE:					
Return on Average Capital Employed (A1/(B1/2))	11.3%	18.7%	22.1%	(39%)	(15%)

[1] Net Financial Items Adjusted for the year is calculated as removing the effects of net financial items after tax, except for mainly accretion expenses.
[2] Calculated Tax on Financial Items for the year is calculated as the net financial items multiplied by the statutory tax rate in the jurisdiction in which the financial items arose.
[3] Capital Employed before Adjustments for each year is reconciled in the table in the section *Net debt to capital employed ratio*.

4.4.2 Unit of production cost

In order to evaluate the underlying development in production costs, the production cost is computed on the basis of entitlement volumes and equity volumes.

Significant parts of Statoil's international production are subject to production sharing agreements with countries' authorities. Under these agreements, we cover our share of the operating expenditures relating to the equity volumes produced. Our international production costs are thus affected by the amount of equity barrels produced more than by the entitlement volumes received. In order to exclude the effects that production sharing agreements (PSA effects) and US royalties have on entitlement volumes, we also provide the unit of production cost based on equity volumes.

The following is a reconciliation of our overall operating expenses with production cost per year as used when calculating the unit of production cost per oil equivalent of entitlement and equity volumes.

Reconcilliation of overall operating expenses to production cost (in NOK billion)	For the year ended 31 December 2013	2012	2011
Operating expenses, Statoil Group	75.0	61.2	59.7
Deductions of costs not relevant to production cost calculation			
Operating expenses in Business Areas non-upstream	30.4	22.2	24.5
Total operating expenses upstream	44.6	38.9	35.2
1) Operation over/underlift	0.4	(0.2)	(1.2)
2) Transportation pipeline/vessel upstream	7.4	5.9	5.2
3) Miscellaneous items	5.4	2.2	2.6
4) Total operating expenses upstream for cost per barrel calculation	31.4	31.0	28.6
Entitlement production used in the cost per barrel calculation (mboe/d)	1,719	1,778	1,643
Equity production used in the cost per barrel calculation (mboe/d)	1,940	2,004	1,850

1) Exclusion of the effect from the over-underlift position in the period. Reference is made to Definitions of reported volumes.

2) Transportation costs are excluded from the unit of production cost calculation.

3) Consists of royalty payments, removal/abandonment estimates, reversal of provision related to the discontinued part of the early retirement pension (See note 19 *Pensions* to the Consolidated financial statements) and the guarantee in connection with the Veslefrikk field which are not part of the operating expenses related to production of oil and natural gas in the period.

4) In 2012, Statoil has elected to adjust Total operating expenses upstream only for the effects of footnotes 1-3 and will no longer present further adjustments related to restructuring and Grane gas purchase.

Production cost (in NOK per boe)*	Entitlement production For the year ended 31 December 2013	2012	2011	Equity production For the year ended 31 December 2013	2012	2011
Production cost per boe	50	48	48	44	42	42

* Production cost per boe is calculated as the Total operating expenses upstream for the last four quarters divided by the production volumes (mboe/d multiplied by number of days) for the corresponding period.

Entitlement volumes are highly affected by the PSA effects. On average, equity volumes exceeded entitlement volumes net of US royalties by 221 mboe per day in 2013, 226 mboe per day in 2012 and 207 mboe per day in 2011. With the same cost basis, but higher volumes, the cost per barrel of equity volumes produced will always be lower than the cost per barrel of entitlement volumes. Based on equity volumes, the average production cost was NOK 44 per boe in 2013 compared to NOK 42 per boe in 2012 and NOK 42 per boe in 2011.

4.4.3 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 short-term 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 GAAP.

Calculation of capital employed and net debt to capital employed ratio (in NOK billion, except percentages)	2013	At 31 December 2012	2011
Shareholders' equity	**355.5**	319.2	278.9
Non-controlling interests	**0.5**	0.7	6.2
Total equity (A)	**356.0**	319.9	285.2
Current finance debt	**17.1**	18.4	19.8
Non-current finance debt	**165.5**	101.0	111.6
Gross interest-bearing debt (B)	**182.5**	119.4	131.5
Cash and cash equivalents	**85.3**	65.2	55.3
Current financial investments	**39.2**	14.9	5.1
Cash and cash equivalents and current financial investments (C)	**124.5**	80.1	60.4
Net interest-bearing debt before adjustments (B1) (B-C)	**58.1**	39.3	71.0
Other interest-bearing elements [1]	**7.1**	7.3	6.9
Marketing instruction adjustment [2]	**(1.3)**	(1.2)	(1.4)
Adjustment for project loan [3]	**(0.2)**	(0.3)	(0.4)
Net interest-bearing debt adjusted (B2)	**63.7**	45.1	76.0
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing debt (A+B1)	**414.0**	359.2	356.1
Capital employed adjusted (A+B2)	**419.7**	365.0	361.2
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	**14.0%**	10.9%	19.9%
Net debt to capital employed adjusted (B2/(A+B2)	**15.2%**	12.4%	21.1%

1) Adjustments 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 a.s. classified as current financial investments.
2) Adjustment marketing instruction adjustment is 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

Our overall risk management includes identifying, evaluating and managing risk in all our activities to ensure safe operations and to achieve our corporate goals.

5.1 Risk factors

We are exposed to a number of risks that could affect our operational and financial performance. In this section, we address some of the key risk factors.

5.1.1 Risks related to our business

This section describes the most significant potential risks relating to our business:

Decline in oil or natural gas prices

A substantial or prolonged decline in oil or natural gas prices would have a material adverse effect on us.

Historically, the prices of oil and natural gas have fluctuated greatly in response to changes in many factors. We do not and will not have control over the risk 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 Organization of the Petroleum Exporting Countries (Opec) and other producing nations to influence global production levels and prices;
- prices of alternative fuels that affect the prices realised under our long-term gas sales contracts;
- government regulations and actions;
- 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 natural gas with certainty. A prolonged decline in oil and natural gas prices will adversely affect our business, the results of our operations, our financial condition, our liquidity and our ability to finance planned capital expenditure. 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 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 our operations in the period in which it occurs. Rapid material and/or sustained reductions in oil, gas or product prices can have an impact on the validity of the assumptions on which strategic decisions are based and can have an impact on the economic viability of projects that are planned or in development. For an analysis of the impact of changes in oil and gas prices on net operating income, see Risk review - Risk management.

Exploratory drilling risks

Exploratory drilling involves numerous risks, including the risk that we will encounter no commercially productive oil or natural gas reservoirs.

This could materially adversely affect our results. Accessing new acreage and maturing resources through high risk exploration drilling activities are the nature of our exploration activities. These risks include risks associated with the execution of drilling and seismic operations and those associated with maturing, unproven resources.

The main contributors to new acreage are concession, bidding rounds and acquisitions. Further, the main contributors to maturing and increasing commercially attractive reserves are geological interpretations and successful exploration drilling and appraisal work. Additionally, Statoil also needs to be focused on optimising our rig capacity by thoughtful deployment and redeployment. Given these risks and operational requirements, we may not effectively acquire acreage, successfully conduct our drilling and appraisal work or optimise our rig capacity resulting in a material adverse effect on the results of our 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.

Failure to find and develop additional reserves

If we fail to acquire or find and develop additional reserves, our reserves and production will decline materially from their current levels.

Successful implementation of our group strategy is critically dependent on sustaining our long-term reserve replacement. If upstream resources are not progressed to proved reserves in a timely manner, we will be unable to sustain the long-term replacement of reserves.

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 we are unable to develop partnerships with national oil companies, our ability to find and acquire or develop additional reserves will be limited.

Our future production is highly dependent on our success in finding or acquiring and developing additional reserves. If we are unsuccessful, we may not meet our long-term ambitions for growth in production, and our future total proved reserves and production will decline, adversely affecting our results of operations and financial condition.

HSE

We are exposed to a wide range of health, safety and environmental risks that could result in significant losses.

Exploration for, and the production, processing and transportation of oil and natural gas - including shale oil and gas - can be hazardous, and technical integrity failure, operator error, natural disasters or other occurrences can result in: oil spills, gas leaks, loss of containment of hazardous materials, water fracturing, blowouts, cratering, fires, equipment failure and loss of well control, among other things. The risks associated with exploration for and the production, processing and transportation of oil and natural gas are heightened in the difficult geographies, climate zones and environmentally sensitive regions in which we operate. The effects of climate change could result in less stable weather patterns, resulting in more severe storms and other weather conditions that could interfere with our operations and damage our facilities. 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.

Security risks

We are exposed to security risk.

Acts of terrorism, such as the attack on the In Amenas gas production facility in Algeria, against our plants and offices, pipelines, transportation or computer systems; or breaches of our security system, could also severely disrupt businesses and operations and result in harm to people. 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 and could result in regulatory action, legal liability, damage to our reputation, a significant reduction in our revenues, an increase in our costs, a shutdown of our operations and a loss of our investments in affected areas, and could have a materially adverse effect on our results of operations and financial condition.

Inadequate systems

Our crisis management systems may prove inadequate.

For our most important activities, we have developed contingency plans to continue or recover operations following a disruption or incident. An 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 our business and operations. Likewise, we have crisis management plans and capability to deal with emergencies at every level of our operations. If we do not respond or are not perceived to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted and our reputation affected.

Competition from other oil and gas companies

We encounter competition from other oil and gas companies in all areas of our operations.

Some of our larger, financially stronger competitors may be able to pay more to gain access to resources, while our smaller competitors may be able to move faster and gain access earlier than us. Gaining access to profitable resources either through the acquisition of licences, exploratory prospects or producing properties is key to ensure the long-term health and sustainability of the business and our failure to do that could have an adverse impact on our performance.

Technology is a key competitive advantage in our industry and a larger company may be able to invest more in developing or acquiring intellectual property rights to technology that we may require. Should our innovation lag behind the industry, our performance could be impeded.

For more information on the competitive environment, see the section *Business overview - Our competitive position*.

Development and production uncertainties

Our development projects and production activities involve many uncertainties and operating risks that can prevent us from realising profits and cause substantial losses.

Our development projects and production activities may be curtailed, delayed or cancelled for many reasons, including equipment shortages or failures, natural hazards, unexpected drilling conditions or reservoir characteristics, pressure or irregularities in geological formations, accidents, mechanical and technical difficulties and industrial action. These projects and activities will also often require the use of new and advanced technologies, which may be expensive to develop, purchase and implement, and may not function as expected. In addition, some of our developments will be located in deep waters or other harsh environments - such as the Gulf of Mexico, the Barents Sea, and offshore Brazil, Tanzania and Angola - or may be in challenging fields (heavy oil fields such as Grane, Peregrino and Mariner) that can exacerbate such problems. There is a risk that development projects that we undertake may not yield adequate returns.

Our development projects and production activities on the NCS also face the challenge of remaining profitable. We are increasingly developing smaller satellite fields in mature areas, and our activities are subject to the Norwegian State's relatively high taxes on offshore activities. In addition, our development projects and production activities, particularly those in remote areas, could become less profitable, or unprofitable, if we experience a prolonged period of low oil or gas prices or cost overruns.

The 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 could reduce the returns and erode the profitability of some of our projects. As a response to this challenge, we will need to at all times evaluate appropriate measures such as adjusting, postponing or stopping projects, adjusting strategies and targets or withdrawing from certain geographical areas.

Challenges in achieving strategic objectives

We face challenges in achieving our strategic objective of successfully exploiting profitable growth opportunities.

An important element of our strategy is to continue to pursue attractive and profitable growth opportunities available to us by both enhancing and repositioning our asset portfolio and expanding into new markets. The opportunities that we are actively pursuing may involve the acquisition of businesses or properties that complement or expand our existing portfolio. The challenges related to the renewal of our upstream portfolio are growing due to increasing global competition for access to opportunities.
Our ability to successfully implement this strategy will depend on a variety of factors, including our 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 our operations;
- arrange financing, if necessary; and
- comply with legal regulations.

As we pursue business opportunities in new and existing markets, we anticipate significant investments and costs in connection with the development of such opportunities. We may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Any failure by us to successfully pursue and exploit new business opportunities could result in financial losses and inhibit growth.
Any such new projects we acquire will require additional capital expenditure and will increase the cost of our discoveries and development. These projects may also have different risk profiles than our existing portfolio. These and other effects of such acquisitions could result in us having to revise either or both of our 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 our day-to-day operations to the integration of acquired operations or properties. We 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 us, if at all, and it may, in the case of equity, be dilutive to our earnings per share.

Transportation infrastructure risks

The profitability of our oil and gas production may be affected by limited transportation infrastructure when a field is in a remote location.

Our ability to exploit economically any discovered petroleum resources beyond our 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 or pipelines to refineries, and natural gas is usually transported by pipeline to processing plants and end users. We may not be successful in our efforts to secure transportation and markets for all of our potential production.

Cyber Security

We are exposed to security threats on our digital infrastructure that could harm our operations.

Failure to maintain sufficient information security barriers increases the risk of our systems being compromised by unauthorised parties, which in turn impacts the confidentiality, integrity and availability of our systems, and through this, our operations.

Political, social and economic instability

Some of our international interests are located in regions where political, social and economic instability could adversely impact our business.

We have assets and operations located in politically, socially and economically diverse regions around the world, including North Africa, the Middle East and Russia, where potential developments such as war, terrorism (as at the In Amenas joint venture in Algeria), border disputes, guerrilla activities, expropriation, nationalisation of property, civil strife, strikes, political unrest, insurrections, piracy and the imposition of international sanctions could occur. Security threats require continuous monitoring. Hostile actions against our staff, our facilities, our transportation systems and our digital infrastructure (cybersecurity) could cause harm to people and disrupt our operations and further business opportunities in these or other regions, lead to a decline in production and otherwise adversely affect our business. This could have a materially adverse effect on the results of our operations and our financial condition.

Political and legal factors

Our operations are subject to political and legal factors in the countries in which we operate.

We have 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. Our 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 controls;
- tax or royalty increases, including retroactive claims;
- nationalisation or expropriation of our assets;
- unilateral cancellation or modification of our 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 us vary greatly from country to country and are hard to predict. If such risks materialise, they could cause us to incur material costs and/or cause our production to decrease, potentially having a materially adverse effect on our operations or financial condition.

Renewable energy challenges

We face challenges in the renewable energy sector.

Policy initiatives in the European market have led to increased investment in renewable energy, primarily in solar and wind power. These policy initiatives, combined with the current low price of imported coal and sluggish economic growth, have increased electricity price volatility in Europe and reduced demand for natural gas in the electricity sector.

Although investment in renewable energy sources is increasing in both North American and Asian markets, market effects in those regions are expected to be more modest than Europe has experienced, as other factors such as shale gas supply (in the case of North America), and increased demand (Asia), are expected to remain dominant market forces.

Statoil's current focus in the renewable energy sector is on developing offshore wind projects in north-western Europe. Government support policies to encourage the development of renewable energy sources play a significant role in fostering growth in the sector. Unless an offshore wind project is eligible for a government support scheme that makes the project economically viable, Statoil refrains from investing in offshore wind projects. Shifts in government policy toward renewable energy, or offshore wind power in particular, could lead us to modify our strategy for new projects in the renewable energy sector.

Adverse changes in tax regimes

We are exposed to potentially adverse changes in the tax regimes of each jurisdiction in which we operate.

We have business operations in many countries around the world, and any of these countries could modify its tax laws in ways that would adversely affect us. Most of our operations are subject to changes in tax regimes in a similar manner to other companies in our industry. In addition, in the long term, the marginal tax rate in the oil and gas industry tends to change with the price of crude oil. Significant changes in the tax regimes of countries in which we operate could have a material adverse effect on our liquidity and results of operations.

Foreign exchange risks

We face foreign exchange risks that could adversely affect the results of our operations.

Our business faces foreign exchange risks because a large percentage of our revenues and cash receipts are denominated in USD, while sales of gas and refined products can be in a variety of currencies, and we pay dividends and a large part of our taxes in NOK. Fluctuations between the USD and other currencies may adversely affect our business and can give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues. See the section *Risk review - Risk management - Managing financial risk*.

Trading and supply risks

We are exposed to risks relating to trading and supply activities.

Statoil is engaged in substantial trading and commercial activities in the physical markets. We also use 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. We also use financial instruments to manage foreign exchange and interest rate risk. Although we believe we have 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. See the section *Risk review - Risk management - Managing financial risk* for more information about risk management. Any of these risks could have an adverse effect on the results of our operations and financial condition.

Failure to meet ethical and social standards

Failure to meet our ethical and social standards, including non-compliance with anti-bribery, anti-corruption and other applicable laws, could damage our reputation and our business.

Our code of conduct, which applies to all employees of the group, hired personnel, consultants, intermediaries, lobbyists and others who act on our behalf, defines our commitment to high ethical standards and compliance with applicable legal requirements wherever we operate. Incidents of ethical misconduct or non-compliance with applicable laws and regulations, including non-compliance with anti-bribery, anti-corruption and other applicable laws, could be damaging to our reputation, competitiveness and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

Adequate insurance coverage

Our insurance coverage may not adequately protect us.

Statoil maintains insurance coverage that includes coverage for physical damage to our oil and gas properties, third-party liability, workers' compensation and employers' liability, general liability, sudden pollution and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. In addition, our insurance is subject to caps, exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

Attracting and retaining management and personnel

We may fail to attract and retain senior management and skilled personnel.

Failure to secure the right level of competence and capacity in the organization through internal deployment/mobility, as well as attracting and retaining senior leaders and skilled personnel could have a significant adverse impact on our ability to operate.

International sanctions

Our activities in certain countries may be affected by international sanctions.

Certain countries, including Iran and Cuba, have been identified by the US State Department as state sponsors of terrorism.

In October 2002, we signed a participation agreement with Petropars of Iran, pursuant to which we assumed the operatorship for the offshore part of phases 6, 7 and 8 of the South Pars gas development project in the Persian Gulf. Statoil's investment in South Pars is fully depreciated and the net book value was zero (0) as of 31 December 2012.

As a result of the merger with Norsk Hydro's oil and gas business in 2007, Statoil became owner of a 75% interest in the Anaran Block in Iran (acquired by Norsk Hydro in 2000). Work on the Anaran project was stopped in 2008, and in September 2011, Statoil signed a settlement agreement to close the exploration service contract and Statoil's rights reverted to the National Iranian Oil Company (NIOC). Also as a result of the merger with Norsk Hydro's oil and gas business, Statoil became the owner and operator of a 100% interest in the Khorramabad exploration block. In September 2006, Norsk Hydro signed the Khorramabad exploration and development contract with NIOC. The gathering of seismic data in the Khorramabad exploration block was completed in the fourth quarter of 2008. The licence expired in November 2010.

The cost recovery relating to South Pars phases 6, 7 and 8 and the Anaran Block has been completed in 2012, except for the recovery of paid taxes and obligations to the Social Security Organization (SSO) Statoil settled its remaining minimum obligations under the Khorramabad exploration and development contract against the cost recovery in respect of the Anaran Block.

During 2013 Statoil has continued to make efforts to settle the tax and social security obligations still outstanding and recovery rights related to the above mentioned projects. It is expected that this process will still continue for some time before being fully concluded, due inter alia to the extensive restrictions arising out of the international sanctions in place against Iran. All social security and tax payments, as well as the payment of minor running costs in Iran during 2013, have been made from Statoil's existing funds in Iran.

Statoil closed its office in Tehran as of 31 July 2013. However, due to local legal requirements, Statoil still has branch offices of Norwegian subsidiaries registered in Tehran. In 2013, as part of its Iran wind-down activity, Statoil also signed a settlement agreement with Petropars as part of the process to fully close the South Pars development project.

Statoil is not involved in any other activities in Iran. Statoil will not make any new or additional investments in Iran under the present circumstances.
See *Disclosure pursuant to Section 13(r) of the Exchange Act*.

In 2009, Statoil voluntarily provided officials from the US State Department with information about its activities and investments in Iran. On 30 October 2010, the US State Department announced that under the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA), Statoil was eligible to avoid sanctions relating to its activities in Iran, because Statoil had pledged to end its investments in Iran's energy sector.

Since 2010, extensive additional international (including EU and US) sanctions against Iran have been adopted which together form a complex set of trade restrictions. Over the same period, Statoil has informed the US Department of State and the Norwegian Ministry of Foreign Affairs (MFA) of its Iran-related activities. The Norwegian MFA has also at several occasions approved specific transactions related to Statoil's cost recovery activity to settle outstanding matters in Iran.

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.

Statoil has an interest in the Shah Deniz gas field in Azerbaijan in which Naftiran Intertrade Co. Ltd. (NICO) has a 10% interest. The Shah Deniz field was excluded, however, from the main operation provisions of EU sanctions promulgated in 2012 and falls within the exemption for certain natural gas projects under section 603 of ITRA described below. See *Business overview - Development and Production International (DPI) - International production - Europe and Asia* for more information.

Statoil previously held an interest in a deep-water exploration block in Cuba. However, the licenses in Cuba were relinquished in 2013 and all activities in Cuba related to the block were completed by 31 December 2013. Statoil has not been awarded any new licences in Cuba during 2013 and has no current plans to conduct any exploration, development or production activity in Cuba. Statoil might still conduct possible spot-trading in Cuban-origin products going forward, in compliance with US and international sanctions.

We are also aware of initiatives by certain US states and US 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 our 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 Organization (SSO). Statoil's activity in Iran during 2013 was focused on a final settlement with the Iranian tax authorities and the SSO relating to the above mentioned agreements. During 2013 Statoil paid the equivalent of USD 6.34 million in tax and SSO to Iranian authorities in local currency (Iranian Rials), from which USD 2.82 million has been booked as expenses in 2013 and the rest have been reversed from previous years' accruals. Also, in 2013 Statoil booked some accruals for additional SSO liabilities equivalent of USD 9.95 million which might be payable in 2014.

The Statoil office in Iran was closed down end July 2013. Following the closure, Statoil received the equivalent of USD 0.28 million from sales of office furniture and other property in local currency. This amount has been booked as revenue. During 2013 Statoil paid for the daily office non-substantial utility charges to Telecommunication, Electricity and Water Organizations.

As part of its wind-down activity, Statoil in 2013 also signed a settlement agreement with its Iranian partner in the South Pars gas project (named Petropars). Following this settlement, Statoil received the equivalent of USD 0.81 million as insurance payment related to its legacy South Pars business. Also this insurance payment has been booked as revenue in 2013.

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 November 1, 2010, Statoil was informed that the company was not considered to be a company of concern based on its previous Iran-related activities. Statoil is not involved in any other activities in Iran. Statoil will not make any investments in Iran under present circumstances.

Statoil generated no net profit from the aforementioned activity in 2013. Payments of the above mentioned nature are expected to be made also in 2014 in relation to Statoil's winding-down efforts.

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 HSE laws and regulations

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase our costs. The enactment of such laws and regulations in the future is uncertain.

We incur, and expect 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 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 our activities or accidents at various facilities owned or previously owned by us and at third-party sites where our products or waste have been handled or disposed of;
- compensation of persons and/or entities claiming damages as a result of our 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 licenses on the NCS, we are 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 our licences. This means that anyone who suffers losses or damage as a result of pollution caused by operations in any of our NCS license areas can claim compensation from us without having to demonstrate that the damage is due to any fault on our part.

Furthermore, in countries where we operate or expect to operate in the near future, new laws and regulations (the imposition of stricter requirements on licenses, increasingly strict enforcement of or new interpretations of existing laws and regulations, the aftermath of operational catastrophes in which we or members of our 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 our facilities;
- meet technical requirements;
- increase monitoring, training, record-keeping and contingency planning; and
- establish credentials in order to be permitted to commence drilling.

Statoil continues to monitor and respond to regulatory changes in the USA following the BP *Deepwater Horizon* oil spill in the US Gulf of Mexico. Statoil has developed and implemented a safety and environmental management system (SEMS programme), and responded to revised federal drilling safety rules and workplace safety rules. In addition, Statoil is participating in the Center for Offshore Safety's efforts, which are focused on improving offshore safety and industry standards. Statoil has experienced a lengthier approval process for drilling permits, approvals of exploration plans, and approvals of oil spill response plans compared with the pre-2010 permitting situation. Statoil has adjusted its permitting processes and is comfortable operating in the new regulatory environment. Although significant additional changes in permitting or regulations are not anticipated at this time, any such significant changes could require Statoil to incur significant costs. Any such changes, delays or recertification could have a material adverse effect on our operations, results or financial condition. See also *Business overview - Applicable laws and regulations-HSE regulation*.

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. In addition, many of our mature fields are producing increasing quantities of water with oil and gas. Our ability to dispose of this water in environmentally acceptable ways may have an impact on our oil and gas production. Our investments in oil sands, shale gas and unconventional resource technologies, such as hydraulic fracturing, may also cause us to incur additional costs as regulation of these technologies continues to evolve. This could affect our operations and profitability with respect to these operations.

If we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment, we could fail to live up to our aspirations of zero or minimal damage to the environment and of contributing to human progress.

General supervision authorities

We are 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, financial regulations and technical and HRS regulations.

Our products are marketed and traded worldwide and therefore subject to competition and antitrust laws at the supranational and national level in multiple jurisdictions. We are exposed to investigations from competition and antitrust authorities, and violations of the applicable laws and regulations may lead to substantial fines. In May 2013, the EFTA Surveillance Authority conducted an unannounced inspection at our main 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 the Platts' Market-On-Close price assessment process. The investigation is not finalized and no conclusions have been made. The products in scope in the investigation are traded worldwide and there is a risk that authorities in other jurisdictions could also bring similar proceedings.

We are also exposed to financial review from financial supervisory authorities such as the Norwegian Financial Supervisory Authorities and the US Securities and Exchange Commission ("SEC"). Reviews performed by these authorities could result in changes to previous accounts and future accounting policies. On 10 March 2014, the Norwegian Financial Supervisory Authority concluded a review of our 2012 financial statements. We have accepted two of the FSA's conclusions following this review but are appealing the third to the Norwegian Ministry of Finance. See note 28 *Subsequent events* to the Consolidated financial statements for further details.

Statoil is listed on both Oslo Stock Exchange and New York Stock Exchange ("NYSE"), and is registered with the SEC. We are 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 Supervisory ("Ptil") supervises all aspects of Statoil 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. We are exposed to supervision from Ptil, and such supervisions could result in audit reports, orders and investigations.

Liberalisation of European gas markets

The formation of a competitive internal gas market within the European Union (EU) and the general liberalisation of European gas markets could adversely affect our business.

The full opening of national gas market arrangements set out in Directive 2003/55/EC represents the formation of a competitive internal gas market within the EU. The regulations have been in effect since 3 March 2011, but the state of implementation in the various member states varies. The general liberalisation of EU gas markets could affect our market position or result in a reduction in prices in our gas sales contracts. Our exposure to spot gas market prices has increased, correspondingly increasing our exposure to price volatility.

The EU initiative that is likely to impact the gas market is a scheme for trading greenhouse gas emission allowances for the cost-effective reduction of such emissions. This strengthens and extends the Emissions Trading Scheme (ETS). The Community-wide quantity of carbon allowances issued each year will decrease in a linear manner from 2013. The ETS can have a positive or negative impact on us, 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 draft guidelines on environment and energy aid.

Policies of the Norwegian State

Political and economic policies of the Norwegian State could affect our 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 tax and environmental laws and regulations, the Norwegian State awards licences for reconnaissance, production and transportation, and it approves, among other things, exploration and development projects, gas sales contracts and applications for (gas) production rates for individual fields. A licence may be awarded for lower production than expected, and the Norwegian State may, if important public interests are at stake, also instruct us 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 licensees' 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, our NCS exploration, development and production activities and the results of our operations could be affected. For more information about the Norwegian State's regulatory powers, see the section *Business overview - Applicable laws and regulations*.

5.1.3 Risks related to state ownership

This section discusses some of the potential risks relating to our business that could derive from the Norwegian State's majority ownership and from our involvement in the SDFI.

Shareholders' interests may not always be aligned

The interests of our majority shareholder, the Norwegian State, may not always be aligned with the interests of our other shareholders, and this may affect our decisions relating to the Norwegian continental shelf (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 us to continue to market the Norwegian State's oil and gas together with our own oil and gas as a single economic unit.

Pursuant to this coordinated ownership strategy, the Norwegian State requires us, in our activities on the NCS, to take account of the Norwegian State's interests in all decisions that may affect the development and marketing of our own and the Norwegian State's oil and gas.

The Norwegian State directly held 67% of our ordinary shares as of March 2014. A majority vote representing more than 50% is required to decide matters put to a vote of shareholders. The Norwegian State therefore effectively has the power to influence the outcome of any vote of shareholders due to the percentage of our shares it owns, including amending our 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 our 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 our shares held by the Norwegian State, could be different from the interests of our other shareholders.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then our mandate to continue to sell the Norwegian State's oil and gas together with our 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 our position in our markets. For further information about the mandate to sell the Norwegian State's oil and gas, see the section *Business overview - Applicable laws and regulations - SDFI oil and gas marketing and sale*.

5.2 Risk management

Our overall risk management approach includes identifying, evaluating and managing risk in all our activities. In order to achieve optimal corporate solutions, we base our risk management on an enterprise-wide risk management approach.

5.2.1 Managing operational risk

We manage risk in order to ensure safe operations and to achieve our corporate goals in compliance with our requirements.

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 an expectation - most commonly a forecast, percentile or target.
We have an enterprise risk management (ERM) approach, which means that we:

- have a risk and reward focus at all levels of the organisation,
- evaluate significant risk exposure relating to major commitments, and
- manage and coordinate risk at the corporate level.

All risks are related to Statoil's value chain, which denotes the value that is added in each step - from access, maturing, project and operation to market. In addition to the economic impact these risks could have on Statoil's cash flows, we also try to avoid HSE and integrity-related incidents (such as accidents, fraud and corruption). Most of the risks are managed by our principal business area line managers. Some operational risks are insurable and are managed by our captive insurance company operating in the Norwegian and international insurance markets.

Our corporate risk committee (CRC) is headed by our chief financial officer and its members include representatives of our 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 our risk policies. The committee meets regularly during the year to support our risk management strategies, including hedging and trading strategies, as well as risk management methodologies. It regularly receives risk information that is relevant to the company from our corporate risk department.

We have developed policies aimed at managing the financial volatility inherent in some of our business exposures. In accordance with these policies, we enter into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the company level, the business areas 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 following section describes in some detail the market risks to which we are exposed and how we manage these risks.

5.2.2 Managing financial risk

The results of our operations depend on a number of factors, most significantly those that affect the price we receive in Norwegian kroner (NOK) for our products.

The factors that influence the results of our operation include: the level of crude oil and natural gas prices, trends in the exchange rate between the US dollar (USD), in which the trading price of crude oil is generally stated and to which natural gas prices are frequently related, and NOK, in which our accounts are reported and a substantial proportion of our costs are incurred; our oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and our own, as well as our partners' expertise and cooperation in recovering oil and natural gas from those reserves; and changes in our portfolio of assets due to acquisitions and disposals.

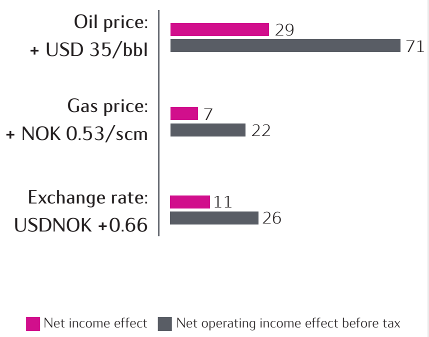
Our results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which we operate, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (Opec) that 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.

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 2013, 2012 and 2011.

Yearly average	2013	2012	2011
Crude oil (USD/bbl Brent blend)	108.7	111.5	111.4
Average invoiced gas price (NOK/scm)	2.0	2.2	2.1
Refining reference margin (USD/bbl)	4.1	5.5	2.3
USDNOK average daily exchange rate	5.9	5.8	5.6

Indicative effects on 2014 results

(NOKbn)



The sensitivity analysis shows the estimated 12 months effect of 1 standard deviation change in parameters.

The illustration shows the indicative full-year effect on the financial result for 2014 given certain changes in the crude oil price, natural gas contract prices and the USDNOK exchange rate.

The estimated sensitivity of our financial results to each of the factors has been estimated based on the assumption that all other factors remain unchanged.

Our oil and gas price hedging policy is designed to support our long-term strategic development and our attainment of targets by protecting financial flexibility and cash flows.

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues and cash flows are mainly denominated in or driven by USD, while our operating expenses and income taxes payable largely accrue in NOK. We seek 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. We also engage in foreign currency management in order to cover our 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 our reported earnings.

Historically, our 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). See the section *Business overview -Applicable laws and regulations - Taxation of Statoil*.

Our earnings volatility is moderated as a result of the significant proportion of our Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by our Norwegian offshore operations in any loss-making periods. Most of the taxes we pay 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 28%. 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 we operate, such as, but not limited to, Algeria, Angola, Nigeria, the USA and Venezuela. 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. Our 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 our total market risk. For this reason, the company 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 our 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, the company 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 our corporate risk committee (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. See note 5 to the Consolidated financial statements, *Financial risk management,* for a discussion of financial risk management.

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* to 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

We are involved in a number of judicial, regulatory and arbitration proceedings concerning matters arising in connection with the conduct of our business.

We are currently not aware of any legal proceedings or claims that we believe may have, or have had in the recent past, individually or in the aggregate, significant effects on our financial position or profitability or on the results of our operations or liquidity (see also note 23 *Other commitments and contingencies* in Consolidated financial statements).

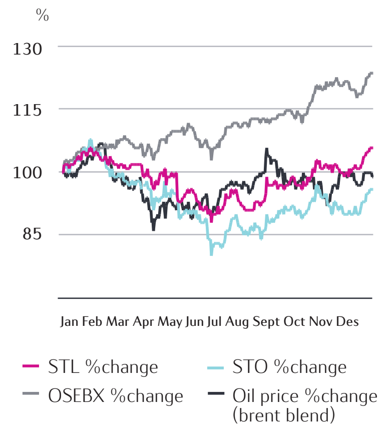
6 Shareholder information

Statoil is the largest company listed on the Oslo stock exchange (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.

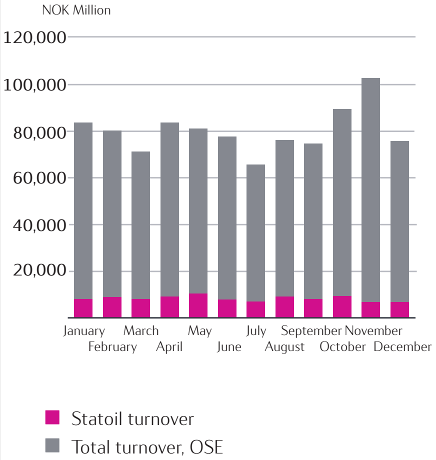
STATOIL SHARE	2013	2012	2011	2010	2009
Share price STL (high) (NOK)	147.70	162.40	160.50	149.20	146.80
Share price STL (low) (NOK)	123.00	133.80	113.70	117.60	108.90
Share price STL (average) (NOK)	136.72	146.97	139.60	131.80	129.50
Share price STL year-end (NOK)	147.00	139.00	153.50	138.60	144.80
Market value-year end (NOK billion)	468	443	490	442	462
Daily turnover (million shares)	2.98	4.3	8.9	9.7	9.6
Ordinary and diluted earnings per share (EPS)(NOK)	12.50	21.60	24.7	11.94	5.74
P/E [1]	11.76	6.44	6.20	11.61	25.18
Total dividend per share (NOK) [2]	7.00	6.75	6.50	6.25	6.00
Ordinary dividend per share (NOK) [2]	7.00	6.75	6.50	6.25	6.00
Special dividend per share (NOK) [2]	0.00	0.00	0.00	0.00	0.00
Growth in ordinary dividend per share [3]	3.7%	3.8%	4.0%	4.2%	36.4%
Growth in total dividend per share	3.7%	3.8%	4.0%	4.2%	(17.2%)
Total dividend per share (USD) [4]	1.15	1.21	1.08	1.07	1.04
Pay-out ratio [5]	56%	31%	26%	52%	104%
Dividend yield [6]	4.8%	4.9%	4.2%	4.5%	4.1%
Ordinary shares outsanding, weighted average	3,180,683,828	3,181,546,060	3,182,112,843	3,182,574,787	3,183,873,643
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 2013.
3) Excluding special dividend and share buy-back.
4) The USD amounts are based on the Norwegian Central Bank's exchange rate at 31 December.
5) Total dividend paid per share divided by EPS.
6) Total dividend paid per share divided by year-end share price.

Quote history



Turnover



As of 31 December 2013, Statoil represented 28.5% of the total value of all companies registered on the Oslo stock exchange, with a market value of NOK 468 billion.

Statoil's share price closed at NOK 147.00 at the end of 2013.

Taking into consideration the dividend of NOK 6.75 per share paid in 2013, the total return was NOK 14.75 per share. The graph above, "Quote history", shows the development of the Statoil share price compared with the oil price and the Oslo Stock Exchange Benchmark Index (OSEBX). The board of directors proposes a dividend of NOK 7.00 per share for 2013, for approval by the annual general meeting on 14 May 2014. The dividend of NOK 7.00 per share proposed to our shareholders is equivalent to a direct yield of approximately 4.8%, and it represents 56% of our net income from 2013. Diluted earnings per share amounted to NOK 12.50, a decrease of 42.1% compared to 2012.

The turnover of shares is a measure of traded volumes. On average, 3.0 million Statoil shares were traded on the Oslo stock exchange every day in 2013 compared to 4.3 million shares in 2012. In 2013, Statoil shares accounted for 12% of the total market value traded throughout the year (see illustration), compared to 16% in 2012.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,180,683,828 ordinary shares outstanding at year end.

As of 31 December 2013, Statoil had 97,373 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 99,845 shareholders at 31 December 2012.

6.1 Dividend policy

It is Statoil's ambition to grow the annual cash dividend, measured in NOK per share, in line with long term underlying earnings.

Changes in the Norwegian company act, in effect from 1 July 2013, allow for dividend payments, based on the company's latest approved annual accounts, to be decided by the board of directors pursuant to an authorisation from the general meeting. The board of directors of Statoil will propose that the shareholders provide such authorisation to the board of directors at the annual general meeting to be held 14 May 2014. Based on such authorisation, Statoil will implement quarterly dividend payments from first quarter 2014, whereby the board approves 1Q -3Q interim dividends, while the annual general meeting approves the 4Q (and total annual) dividend based on a proposal from the board. Statoil will announce 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. Hence, in 2014 Statoil will pay the 2013 annual dividend and two quarterly dividends.

The board of directors has decided to update the dividend policy to reflect the quarterly payment frequency, as follows:

"It is Statoil's ambition to grow the annual cash dividend, measured in NOK per share, in line with long term underlying earnings. Statoil announces dividends on a quarterly basis. The board approves 1Q -3Q interim dividends based on an authorisation from the general meeting, while the annual general meeting approves the 4Q (and total annual) 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."

Implementation of the new dividend policy is conditional upon the general meeting authorising the board of directors to decide payment of quarterly dividends. Such authorisation must be renewed at each annual general meeting in order to remain valid.

6.1.1 Dividends

Dividends for a fiscal year have so far been declared at Statoil's annual general meeting the following year. The Norwegian Public Limited Companies Act forms the legal framework for dividend payments and this legal framework was amended with effect from 1 July 2013. This change allows for dividend payments to be decided by the board of directors pursuant to an authorisation from the general meeting. Such authorisation may be valid until the next annual general meeting.

Statoil is in favour of the changed legal framework for capital distribution and will implement quarterly dividend payments in 2014, assuming AGM approval 14 May 2014, ref. section 6.1. Quarterly dividend payments will further align Statoil's capital distribution practice with its peers. The shareholders at the AGM may vote to reduce, but may not increase, the fourth quarter (and hence total year) dividend proposed by the board of directors.

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 paid to all shareholders since 2009 on a per share basis and in aggregate, as well as the cash dividend proposed by our board of directors to be paid in 2014 on our ordinary shares for the fiscal year 2013.

Fiscal Year	Ordinary dividend per share NOK	Total NOK billion
2009	6.00	19.1
2010	6.25	19.9
2011	6.50	20.7
2012	6.75	21.5
2013*	7.00	22.3

* Proposed dividend

The proposed dividend for 2013 will be considered at the annual general meeting on 14 May 2014. The Statoil share will be traded ex-dividend from 15 May 2014 and, if approved, the dividend will be disbursed on 28 May 2014. For US ADR holders, the ex-dividend date will be 15 May 2014. The payment date for dividend in USD to US ADR holders is expected to be 4 June 2014.

Since we will only pay dividends in Norwegian kroner (NOK), exchange rate fluctuations will affect the amounts in US dollars (USD) received by holders of ADRs after the ADR depositary converts cash dividends into USD. The dividend will be made available to the depositary on 28 May 2014. The depositary will convert the dividend into USD at the prevailing exchange rate for NOK and pay the US ADR holders the USD equivalent of the dividend in NOK, minus the prevailing bank charges.

Share repurchases
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 2013-2014, 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 repurchases based on this authorisation.

A prerequisite for share repurchases is an authorisation from the annual general meeting. Statoil intends to use share buybacks more active going forward, based on transaction proceeds, cash flow developments and balance sheet strength.

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 2013.

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 250). 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 27.5 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 2014. 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 on 15 May 2012.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 27.5 million, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than 11 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 program	Maximum number of shares that may yet be purchased under the program authorisation
Jan-13	614,100	142.3138	4,670,350	6,329,650
Feb-13	619,000	143.2733	5,289,350	5,710,650
Mar-13	633,500	140.6304	5,922,850	5,077,150
Apr-13	660,500	135.1076	6,583,350	4,416,650
May-13	685,850	130.6404	7,269,200	3,730,800
Jun-13	705,300	127.0376	705,300	10,294,700
Jul-13	686,600	130.9198	1,391,900	9,608,100
Aug-13	696,750	128.8810	2,088,650	8,911,350
Sep-13	668,000	134.9473	2,756,650	8,243,350
Oct-13	658,900	137.3388	3,415,550	7,584,450
Nov-13	644,400	141.2110	4,059,950	6,940,050
Dec-13	645,640	141.7197	4,705,590	6,294,410
Jan-14	601,685	152.9055	5,307,275	5,692,725
Feb-14	588,350	158.0552	5,895,625	5,104,375
TOTAL	9,108,575 (2)	138.4873 (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 15 May 2012. The authorisation was maintained by the annual general meeting on 14 May 2013 at a maximum of 11 million shares with a maximum overall nominal value of 27.5 million for repurchase of shares, valid until 30 June 2014.

(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 stock exchange (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 stock exchange in Norway, the Securities and Exchange Commission in the US and our website Statoil.com.

Our registrar manages our shares listed on the Oslo stock exchange 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 Stock Exchange: STL
New York Stock Exchange: STO
Reuters: STL.OL
Bloomberg: STL NO

Financial calendar for 2014

07 February	Fourth quarter results and strategy update
21 March	Publication annual report 2013
29 April	First quarter 2014
14 May	Annual general meeting
15 May	Ordinary share trading ex-dividend
15 May	ADS trading ex-dividend
28 May	Ordinary share dividend payment
4 June	ADS dividend payment
25 July	Second quarter 2014
29 October	Third quarter 2014

6.4 Market and market prices

The principal trading market for our ordinary shares is the Oslo stock exchange. 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 stock exchange 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 from 31 January 2013 (previously Bank of New York Mellon) 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 stock exchange and New York Stock Exchange for the periods indicated.

They are derived from the Oslo Stock Exchange 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				
2009	146.80	108.90	26.41	15.11
2010	149.20	117.60	26.47	18.68
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
Quarter ended				
Saturday, March 31, 2012	162.40	147.10	28.92	24.88
Saturday, June 30, 2012	156.50	133.80	27.53	22.15
Sunday, September 30, 2012	154.50	140.10	26.99	23.02
Monday, December 31, 2012	148.70	135.40	26.30	23.58
Sunday, March 31, 2013	146.90	140.50	27.00	24.21
Sunday, June 30, 2013	141.40	123.00	24.58	24.16
Monday, September 30, 2013	137.60	125.50	23.09	20.43
Tuesday, December 31, 2013	147.70	133.30	24.18	22.23
March up until 13 March 2014	164.10	146.40	27.18	23.37
Month of				
September 2013	137.50	132.90	23.09	21.95
October 2013	143.00	133.30	24.18	22.23
November 2013	142.20	138.00	23.77	22.44
December 2013	147.70	138.20	24.13	22.49
January 2014	154.80	146.40	25.01	23.67
February 2014	161.10	147.40	26.52	23.37
March up until 13 March 2014	164.10	161.30	27.18	26.87

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 2013, the depositary reimbursed no expenses to the company.

Category of expenses	USD amount reimbursed for the year ended 31 December 2013
Total amount reimbursed	0

* In 2014, Statoil expects to receive a reimbursement payment from the Depositary of approximately USD 3 million in relation to certain expenses including investor relations expenses, expenses related to the maintenance of the ADR program, legal counsel fees, printing, ADR certificates, etc.

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.

The table below sets forth the expenses that the depositary waived or paid directly to third parties in the year ended 31 December 2013:

Category of expenses	USD amount waived or paid for the year ended 31 December 2013
Total amount paid directly to third parties	68,000

Under certain circumstances, including removal of the depositary or termination of the ADR programme by the company, the company is required to repay to the depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the twelve-month period prior to notice of removal or termination.

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 ADSs.

Norwegian tax matters
This section 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). This section 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 subject to tax in Norway on dividends. The basis for taxation is 3% of the dividends received, which is subject to the standard 27% income tax rate (28% in 2013).

Individual shareholders resident in Norway for tax purposes are subject to the standard 27% income tax rate (28% in 2013) in Norway for dividend income exceeding a basic tax free allowance. The tax free allowance is computed for each individual shareholder on the basis of the cost price of each of the shares multiplied by a risk-free interest rate. The risk-free interest rate will be calculated every income year. Any part of the calculated allowance for one year that exceeds the dividend distributed for the share ("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. Any unused allowance will also be added to the basis for computation of the allowance for the same share 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 the beneficial owner of the dividends and 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 the shares of the distributing company, the withholding tax rate on dividends may be further reduced. The reduced withholding rate will only apply to dividends paid for shares held directly by holders who are able to properly demonstrate to the company that they are entitled to the benefits of the tax treaty. It is the responsibility of the distributing company to deduct the withholding tax when dividends are paid to non-resident shareholders.

The withholding tax rate in the tax treaty between the United States and Norway is currently 15% in all cases. Dividends paid to the depositary for redistribution to shareholders who hold American Depositary Shares (ADS) will in principle 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.

An application for a refund of withholding tax from shareholders and ADS holders must contain the following:

1. Full name, address and tax identification number.
2. IBAN (International Bank Account Number) and SWIFT/BIC code for the bank account to which the refund is to be credited. COFTA also needs to know who the owner of the account is. The account must be able to accept NOK.
3. A specification of the company(ies) involved, the exact number of shares, the date the dividend payments were made, the total dividend payment, the withholding tax deducted in Norway and what amount is being reclaimed. The withholding tax must be calculated in Norwegian currency and all sums specified accordingly (in NOK).
4. A certificate of residence issued by the tax authorities stating that the refund claimant was resident for tax purposes in that state in the income year in question or at the time the dividends were decided. This documentation must be in the original. If the claimant is an investment fund, the confirmation must solely mention the fund's name. A confirmation in the fund manager's name is not sufficient. The confirmation must be in the original.
5. Documentation showing that the refund claimant has received the dividends and the withholding tax rate used in Norway (a credit advice).
6. If the refund application is based on the particular rules applicable to EEA shareholders, the application must also contain the information required to determine whether these rules are applicable.
7. The information required to decide whether the refund claimant is the beneficial owner of the dividend payment(s).
8. If the securities are registered with a foreign custodian/bank/clearing house, the claimant must provide information about which foreign custodian/bank/clearing house the securities are registered with in Norway.
9. The application must be signed by the applicant. If someone else signs the application, a letter of authorisation must be enclosed. The claimant must also specifically confirm that the person signing the application is authorised to apply for a refund of withholding tax levied on those particular dividend payments. The application must therefore also be accompanied by a spreadsheet listing the names of the companies from which the dividends were received, the payment date, dividend payment, withheld tax and which amount is being reclaimed. This spreadsheet must be approved and signed by the claimant. It is not sufficient to only enclose a general letter of authorisation.

Deutsche Bank Trust Company Americas, acting as depositary, has been granted permission by the Norwegian tax authorities to receive dividends from us for redistribution to a beneficial owner of shares or ADSs at the applicable treaty withholding rate, if the beneficial holder has provided Deutsche Bank Trust Company Americas with appropriate documentation establishing such holder's eligibility for the benefits under the tax treaty with Norway.

Corporate shareholders that carry on business activities in Norway, and whose shares 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 27% income tax rate (28% in 2013).

Taxation on the realisation of shares

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 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. Gains or losses in connection with such realisation are included in or deducted from the individual's ordinary taxable income in the year of disposal, and are subject to the standard 27% income tax rate (28% in 2013).

The taxable gain or loss 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. Any unused allowance pertaining to a share may be deducted from a capital gain on the same share, 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.

If the shareholder disposes of shares acquired at different times, the shares 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.

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 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 1% of the value assessed (1.1% in 2013). The assessment value of listed shares is 100% of the listed value of such shares on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares 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

There is no inheritance tax for gifts given from 1 January 2014, or inheritance received on the basis of a death occurring from 1 January 2014.

For shares or ADSs received as a gift before 1 January 2014 or as inheritance on the basis of a death occurring before 1 January 2014, such transfer may give rise to inheritance tax in Norway if the donor, at the time of the gift, or the deceased, at the time of death, was a resident or citizen of Norway. However, if a Norwegian citizen was not a resident of Norway at the time of his or her death, Norwegian inheritance tax will not be levied if inheritance tax or a similar tax is levied by the country of residence. Irrespective of citizenship, Norwegian inheritance tax may be levied if the shares or ADSs are effectively connected with the conducting of a trade or business through a permanent establishment in Norway.

Transfer tax

No transfer tax is imposed in Norway in connection with the sale or purchase of shares.

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 advisor 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.

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 and 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.

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
2009	5.5433	7.2048	6.2898	5.7767
2010	5.6026	6.6840	6.0437	5.8564
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

	Low	High
2013		
September	5.7896	6.1005
October	5.8742	6.0523
November	5.9355	6.2154
December	6.0837	6.1849
2014		
January	6.0979	6.2970
February	5.9907	6.3022
March (up to and including 13 March 2014)	5.9228	6.0412

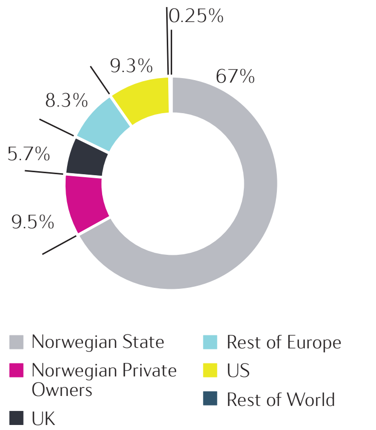
On 13 March 2014, the exchange rate announced by Norges Bank for the Norwegian krone was USD 1.00 = NOK 5.9228.

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.

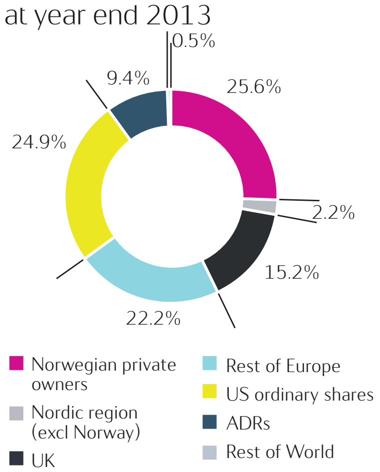
6.8 Major shareholders

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.

Distribution of shareholders at year end 2013



Free float breakdown at year end 2013



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 2013, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.4% indirect interest through the National Insurance Fund (Folketrygdfondet), totalling 70.4%.

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 2013.

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 more than 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 13 March 2014	Account type	Number of Shares	Ownership in %
1	The Norwegian State (Ministry of Petroleum and Energy)		2,136,393,559	67.00
2	FOLKETRYGDFONDET (Norwegian national insurance fund)		106,383,737	3.34
3	DEUTSCHE BANK TRUST CO. AMERICAS	Nominee	101,451,951	3.18
4	CLEARSTREAM BANKING	Nominee	71,712,652	2.25
5	STATE STREET BANK AND TRUST CO.	Nominee	21,900,426	0.69
6	STATE STREET BANK AND TRUST CO.	Nominee	19,466,771	0.61
7	J.P. Morgan Chase Ba NORDEA TREATY ACCOUN	Nominee	19,431,246	0.61
8	The Bank of New York Mellon	Nominee	17,743,668	0.56
9	EUROCLEAR BANK	Nominee	17,492,006	0.55
10	J.P. MORGAN CHASE BANK	Nominee	17,072,394	0.54
11	STATE STREET BANK AND TRUST CO.	Nominee	16,387,219	0.51
12	THE NORTHERN TRUST COMPANY	Nominee	15,200,000	0.48
13	STATE STREET BANK AND TRUST CO.	Nominee	14,420,734	0.45
14	The Bank of New York Mellon	Nominee	13,107,605	0.41
15	SIX SIS AG	Nominee	12,689,989	0.40
16	HSBC BANK PLC	Nominee	10,497,584	0.33
17	KLP AKSJE NORGE		9,885,455	0.31
18	The Bank of New York Mellon	Nominee	9,596,370	0.30
19	BNYM SA/NV - BNY BRUSSELS NON-TREA	Nominee	8,988,648	0.28
20	THE NORTHERN TRUST COMPANY	Nominee	8,884,711	0.28

Source: Norwegian Central Securities Depositary (VPS)

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 our corporate objective, we are 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. We believe 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.

Our governing structures and controls help to ensure that we run our business in a profitable manner for the benefit of our shareholders, employees and other stakeholders in the societies in which we operate.

The following principles underline our 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 the company's 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 there not being any 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, if applicable, 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 our articles of association:

Name of the company
Our registered name is Statoil ASA. We are a Norwegian public limited company.

Registered office
Our 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 our company, as set forth in Article 1, is, either by ourselves 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
Our 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
Our articles of association provide that our board of directors shall consist of 9 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
We have 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
Our 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 our 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 our 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
Our articles of association provide that we are 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 our own production. Our 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 Ethics Code of Conduct

Together with Statoil's values statement, the Ethics Code of Conduct constitutes the basis and framework for our performance culture.

Our ability to create value is dependent on applying high ethical standards, and we are determined that Statoil will be known for such standards. Ethics is treated as an integral part of our business activities. We demand high ethical standards of our employees and everyone who acts on our behalf, and we will conduct an open dialogue on ethical issues, both internally and externally.

Statoil's Ethics Code of Conduct describes our commitment and requirements in connection with issues of an ethical nature that relate to business practice and personal conduct.

In our business activities, we will comply with applicable laws and regulations and act in an ethical, sustainable and socially responsible manner. Respect for human rights is an integral part of Statoil's values base.

The Ethics Code of Conduct applies to the company and its individual employees, board members, hired personnel, consultants, intermediaries, lobbyists and others who act on Statoil's behalf, including the chief executive officer, the chief financial officer and the principal accounting controller. In 2013 we implemented a mandatory certification of compliance with the Ethics Code of Conduct. All Statoil's employees have to certify knowledge of and make a commitment to comply with the Ethics Code of Conduct. In the annual review of the Ethics Code of Conduct in 2013 the Board of Directors approved minor adjustments to clarify and simplify the document. The Ethics Code of Conduct is available at Statoil.com, together with our anti-corruption compliance programme.

Statoil runs various ethics and anti-corruption training programmes. In 2013, 606 persons attended a full-day ethics and anti-corruption workshop focusing on the requirements in our code of conduct and applicable anti-corruption laws and regulations. Training in ethics and anti-corruption will continue in 2014.

Our business partners are also expected to adhere to ethical standards that are consistent with our ethical requirements.

We have an externally operated ethics helpline that can be used by employees on an 24/7 basis to express concerns regarding Statoil's business and activities. A description of the ethics helpline is available at www.statoil.com/ethicshelpline.

7.3 General meeting of shareholders

The general meeting of shareholders is our supreme corporate body. The objective of the general meeting is to ensure shareholder democracy. We encourage all shareholders to participate in person or by proxy.

The general meeting of shareholders is the company's supreme corporate body. The 2014 annual general meeting (AGM) is scheduled for 14 May 2014 in Stavanger, Norway, with simultaneous transmission by webcast. 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 the company'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. Shareholders who are prevented from attending 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 stipulation of the corporate assembly's fees
- Election of the nomination committee and stipulation of the nomination committee's fees
- Election of the external auditor and stipulation 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 AGMs 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 AGM.

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 our 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, we outline certain types of resolutions by the general meeting of shareholders:

New share issues
If we issue any new shares, including bonus shares, our articles of association must be amended. This requires the same majority as other amendments to our articles of association. In addition, under Norwegian law, our shareholders have a preferential right to subscribe for new shares issued by us. 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 our 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 US may require us to file a registration statement in the US under US securities laws. If we decide not to file a registration statement, these holders may not be able to exercise their preferential rights.

Right of redemption and repurchase of shares
Our articles of association do not authorise the redemption of shares. In the absence of authorisation, the redemption of shares may nonetheless be decided 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 the company'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, Folketrygdfondet
- Tom Rathke, group executive vice president Wealth Management at DnB
- Elisabeth Berge, Secretary General, Norwegian Ministry of Petroleum and Energy

Effective as from 4 June 2013, Live Haukvik Aker withdrew from her position in the nomination committee as she had been elected as member of the board of directors of Kværner ASA.

The nomination committee held 15 ordinary meeting and three telephone meetings in 2013.

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 31.12.2013	Share ownership for members as of 13.03.2014	First time elected	Expiration date of current term
Olaug Svarva	Managing director, Folketrygdfondet	Oslo	1957	Chair, Shareholder-elected	No	0	0	2007	2014
Idar Kreutzer	CEO, Finance Norway (FNO)	Oslo	1962	Deputy chair, Shareholder-elected	No	0	0	2007	2014
Karin Aslaksen	Head of HR department, the National Police Directorate of Norway	Hosle	1959	Shareholder-elected	No	0	0	2008	2014
Greger Mannsverk	Managing director, Bergen Group Kimek AS	Kirkenes	1961	Shareholder-elected	No	0	0	2002	2014
Steinar Olsen	CEO, Jemso A/S	Stavanger	1949	Shareholder-elected	No	0	0	2007	2014
Ingvald Strømmen	Dean at Norwegian University of Science and Technology (NTNU)	Ranheim	1950	Shareholder-elected	No	0	0	2006	2014
Rune Bjerke	President and CEO, DNB ASA	Oslo	1960	Shareholder-elected	No	0	0	2007	2014
Tore Ulstein	Chairman of the Board and Deputy CEO, Ulstein Group and President of NHO (the Confederation of Norwegian Enterprise)	Ulsteinvik	1967	Shareholder-elected	No	0	0	2008	2014
Thor Oscar Bolstad	Manager, Herøya Industripark, Norsk Hydro ASA	Porsgrunn	1954	Shareholder-elected	No	0	0	2010	2014
Barbro Hætta	Medical doctor, University Hospital of North Norway	Harstad	1972	Shareholder-elected	No	0	0	2010	2014
Siri Kalvig	Employee, StormGeo AS	Stavanger	1970	Shareholder-elected	No	0	0	2010	2014
Eldfrid Irene Hognestad	Union representative Tekna, Advisor Benchmarking	Stavanger	1966	Employee-elected	No	727	824	2009	2015
Steinar Kåre Dale	Union representative, NITO, SR Analyst	Mongstad	1961	Employee-elected	No	1,545	1,793	2013	2015
Per Martin Labråten	Union representative, Industri Energi. Production technician	Brevik	1961	Employee-elected	No	1,473	1,650	2007	2015
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee-elected	No	3,552	3,845	2006	2015
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee-elected	No	489	377	2008	2015
Hilde Møllerstad	Union representative, Tekna/NITO	Oslo	1966	Employee-elected	No	1,641	1,694	2013	2015
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee-elected, observer	No	2,031	2,215	1994	2015
Dag-Rune Dale	Union representative, Industri Energi, Safety officer	Kollsnes	1963	Employee-elected, observer	No	2,014	2,229	2013	2015
Brit Gunn Ersland	Union representative, Tekna. Specialist Reservoir Tech.	Bergen	1960	Employee-elected, observer	No	2,268	2,479	2011	2015
					Total	15,740	17,106		

An election of the employee-elected members in the corporate assembly was held early 2013. Effective as of 29 April 2013, Steinar Kåre Dale and Hilde Møllerstad were elected as members and Dag-Rune Dale (former deputy member) was elected as observer to the corporate assembly. Stig Lægreid and Oddbjørn Viken left the corporate assembly as of the same date, while Frode Solberg left the position as an observer (but was elected deputy member).

Effective as of 4 June 2013, Live Haukvik Aker, CFO/COO of Komplett AS, withdrew from her position as a shareholder-elected member of the corporate assembly as she had been elected to the board of directors in Kværner ASA. A new election of all shareholder representatives in the corporate assembly will be held in May 2014.

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 and one extraordinary meeting in 2013.

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 will consist of between nine and 11 members. The management is not represented on the board, and all shareholder representatives on the board are independent.

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 judgement, all of the shareholder representatives on the board are independent as defined by the Norwegian Code of Practice for Corporate Governance.

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 six extraordinary meetings in 2013. Average attendance at these board meetings was 99.27%.

Members of the board of directors

Figure 7.1 Svein Rennemo

Svein Rennemo
Born: 1947
Position: Chair of the board and member of the board's compensation and executive development committee.
Term of office: Chair of the board of Statoil ASA since 1 April 2008. Up for election in 2014.
Independent: Yes
Other directorships: Chair of the board of Tomra Systems ASA.
Number of shares in Statoil ASA as of 31 December 2013: 10,000
Loans from Statoil: None
Experience: Rennemo was CEO of Petroleum Geo-Services ASA from 2002 until 1 April 2008 (when he took up office as chair of the board of Statoil ASA). From 1994 to 2001, Rennemo worked for Borealis, first as deputy CEO and CFO and, from 1997, as CEO. He held various management positions in Statoil from 1982 to 1994, most recently as head of the petrochemical division. During the period 1972 to 1982, he was an analyst and monetary policy and economics adviser at Norges Bank (the Norwegian central bank), the OECD Secretariat in Paris and the Norwegian Ministry of Finance.
Education: Economist, 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 2013, Svein Rennemo participated in eight ordinary board meetings, six extraordinary board meetings and six meetings of the compensation and executive development committee. Rennemo is a Norwegian citizen and resident in Norway.

Figure 7.2 Grace Reksten Skaugen

Grace Reksten Skaugen
Born: 1953
Position: Deputy chair of the board and chair of the board's compensation and executive development committee.
Term of office: Member of the board of Statoil ASA since 2002. Up for election in 2014.
Independent: Yes
Other directorships: Chair of the board of the Norwegian Institute of Directors, Deputy chair of the board of Orkla ASA and board member of the Swedish listed company Investor AB. Chair of the board of NAXS Nordic Access Buyout A/S, a Norwegian subsidiary of the Swedish listed company Nordic Access Buyout Fund AB.
Number of shares in Statoil ASA as of 31 December 2013: 400
Loans from Statoil: None
Experience: Self-employed business consultant. She was a director in corporate finance in SEB Enskilda Securities in Oslo from 1994 to 2002. She has previously worked in the fields of venture capital and shipping in Oslo and London and carried out research in microelectronics at Columbia University in New York.
Education: She has a doctorate in laser physics from the Imperial College of Science and Technology at the University of London and an MBA from the Norwegian School of Management (BI).
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2013, Grace Reksten Skaugen participated in eight ordinary board meetings, six extraordinary board meetings and six meetings of the compensation and executive development committee. Reksten Skaugen is a Norwegian citizen and resident in Norway.

Figure 7.3 Bjørn Tore Godal

Bjørn Tore Godal
Born: 1945
Position: Member of the board, member of the board's compensation and executive development committee and chair of 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 2014.
Independent: Yes
Other directorships: Chairman of the Council of the Norwegian Defence University College (NDUC), and member of the board of the Fridtjof Nansen Institute (FNI).
Number of shares in Statoil ASA as of 31 December 2013: None
Loans from Statoil: 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 defence, and minister of foreign affairs for a total of eight years between 1991 and 2001.
From 2007-2010, he was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs.
From 2003-2007, he 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 2013, Bjørn Tore Godal participated in eight ordinary board meetings, six extraordinary board meetings, six meetings of the board's compensation and executive development committee and five meetings of the board's safety, sustainability and ethics committee. Godal is a Norwegian citizen and resident in Norway.

Figure 7.4 Jakob Stausholm

Jakob Stausholm
Born: 1968
Position: 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 2014.
Independent: Yes
Other directorships: No
Number of shares in Statoil ASA as of 31 December 2013: 32,600
Loans from Statoil: None
Experience: Chief strategy, finance 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 2013, Jakob Stausholm participated in eight ordinary board meetings, six extraordinary board meetings and six meetings of the board's audit committee. Stausholm is a Danish citizen and resident in Denmark.

Figure 7.5 Maria Johanna Oudeman

Maria Johanna Oudeman
Born: 1958
Position: Member of the board and member of the board's audit committee.
Term of office: Member of the Board of Statoil ASA from 15 September 2012. Up for election in 2014.
Independent: Yes
Other directorships: Oudeman is a member of the boards, ABN Amro Group, Het Concertgebouw and Rijksmuseum.
Number of shares in Statoil ASA as of 31 December 2013: None
Loans from Statoil: None
Experience: Marjan 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, Oudeman 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 2013, Marjan Oudeman participated in eight ordinary board meetings, six extraordinary board meetings and six meetings of the board's audit committee. Oudeman is a Dutch citizen and resident in the Netherlands.

Figure 7.6 James Mulva

James Mulva
Born: 1946
Position: 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 since 1 July 2013. Up for election in 2014.
Independent: Yes
Other directorships: James Mulva is a non-executive director of the American multinational automotive corporation General Motors Corporation and the multinational conglomerate corporation General Electric Company. He is also a director of Green Bay Packaging and Vice Chairman of M.D. Anderson Cancer Centre, Houston.
Number of shares in Statoil ASA as of 31 December 2013: None
Loans from Statoil: None
Experience: James Mulva was president and CEO of Houston-based ConocoPhillips from 2002 until retirement in 2012. From 2004 to 2012 he also served as chairman of the board. Prior to this he was chairman, president and CEO of Phillips Petroleum from 1999 to 2002. Mulva started his career in the oil and gas industry with Phillips Petroleum Company in 1973 and held positions within the finance area, being chief financial officer (CFO) from 1990 -1993. He served as chief operating officer (COO), responsible for all operations including refineries, offshore and onshore activities from 1994 to 1999.
Education: Master of Business Administration from the University of Texas, USA.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2013, James Mulva participated in four ordinary board meetings, four extraordinary board meetings and two meetings of the board's safety, sustainability and ethics committee. James Mulva is an American citizen and resident in Houston, Texas, USA.

Figure 7.7 Catherine Hughes

Catherine Hughes
Position: Member of the board and member of the board's audit committee.
Born: 1962
Term of office: Member of the board of directors of Statoil ASA since 1 July 2013. Up for election in 2014.
Independent: Yes
Other directorships: Member of the board of directors of the Canadian oilfield services company Precision Drilling Corporation.
Number of shares in Statoil ASA as of 31 December 2013: None
Loans from Statoil: None
Experience: Catherine Hughes has an extensive career within the oil and gas industry. From 2009 to 2013 she worked for Nexen, located in Alberta, Canada, first as vice president (VP) operational services, technology and HR and from 2012 as executive vice president responsible for all activities outside Canada. From 2005 to 2009, she was VP exploration and production services then VP oil sands at Husky Oil. Prior to that Hughes spent 20 years with Schlumberger and held key positions in various countries including Nigeria, Italy, France, UK, Canada and USA.
Education: Hughes holds a Bachelor of Science degree in electrical engineering from Institut National des Sciences Appliquées de Lyon.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2013, Catherine Hughes participated in four ordinary board meetings, four extraordinary board meetings and three meetings of the board's audit committee. Catherine Hughes is a Canadian/French citizen resident in Alberta, Canada.

Figure 7.8 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 2015.
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 2013: 330
Loans from Statoil: None
Experience: She 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 IE 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 2013, Lill-Heidi Bakkerud participated in eight ordinary board meetings, six extraordinary board meetings and five meetings of the board's safety, sustainability and ethics committee. Bakkerud is a Norwegian citizen and resident in Norway.

Figure 7.9 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 2015.
Independent: No
Other board 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 2013: 1,778
Loans from Statoil: None
Experience: Has been employed by Statoil since 2005. Works within materials discipline for Technology, Projects & Drilling. Was 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).
Familial relationships: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2013, Ingrid di Valerio participated in four ordinary board meetings, four extraordinary board meetings and three meetings of the board's audit committee. Ingrid Di Valerio is a Norwegian citizen and resident in Norway.

Figure 7.10 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 2015.
Independent: No
Other board directorships: Member of executive committee of The Norwegian society for Engineers and Technologists (NITO) and NITO's negotiation committee for private sector
Number of shares held in Statoil ASA as of 31 December 2013: 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 NITO, Statoil.
Education: Bachelor degree, mechanical construction from OIH.
Familial relationships: No family relationships to other board members, members of the corporate executive committee or the corporate assembly.
Other: In 2013, Stig Lægreid participated in four ordinary board meetings, three extraordinary board meetings and two meetings of the board's safety, sustainability and ethics committee. Stig Lægreid is a Norwegian citizen and resident in Norway.

In addition, there are five 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 2013, the audit committee members were Jakob Stausholm (chair), Maria Johanna Oudeman, Catherine Hughes, 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 Ethics 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 Ethics Code of Conduct or statutory provisions. 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 2013. There was 100% 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, Maria Johanna Oudeman and Catherine Hughes 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 compensation and executive development committee is a sub-committee of the board of directors and its main responsibilities 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 executives 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 three board members. At year-end 2013, the committee members were Grace Reksten Skaugen (chair), Svein Rennemo and Bjørn Tore Godal. All of the committee members are independent, non-executive directors.

The committee held six meetings in 2013 and attendance was 100%.

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.

Statoil's board of directors has established a sub-committee dedicated to the areas of safety, sustainability and ethics. The safety, sustainability and ethics committee (the committee) is chaired by Bjørn Tore Godal, and the other members are James Mulva, 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.

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.

The committee held five meetings in 2013, and attendance was 95.24%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the committee available at www.statoil.com/ssecommittee.

7.7 Compliance with NYSE listing rules

Statoil's primary listing is on the Oslo stock exchange (Oslo Børs), but the company is also registered as a foreign private issuer with the US Securities and Exchange Commission.

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. 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 judgement, all of the shareholder-elected directors are independent. In making its determinations of independence, the board focuses on there not being any conflicts of interest between shareholders, the board of directors and the company's management, but it does not explicitly take into consideration 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.

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.

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's. 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 development and 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

Figure 7.11 Helge Lund. Chief executive officer

Helge Lund
Born: 1962
Position: President and chief executive officer (CEO) of Statoil ASA since August 2004.
External offices: Member of the board of directors of Nokia.
Number of shares in Statoil ASA as of 31 December 2013: 61,151
Loans from Statoil: None
Experience: Came to Statoil from the position of CEO of Aker Kværner ASA, and held central managerial positions in the Aker RGI system from 1999. He has been political adviser to the Conservative Party of Norway's parliamentary group, a consultant with McKinsey & Co and deputy managing director of Nycomed Pharma AS.
Education: MA in business economics (siviløkonom) from the Norwegian School of Economics and Business Administration (NHH) in Bergen and master of business administration (MBA) from INSEAD in France.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Helge Lund is a Norwegian citizen and resident in Norway.

Figure 7.12 Torgrim Reitan. Chief financial officer (CFO)

Torgrim Reitan
Born: 1969
Position: Executive vice president and chief financial officer (CFO) of Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2013: 20,301
Loans from Statoil: None
Experience: 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, he 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.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Torgrim Reitan is a Norwegian citizen and resident in Norway.

Figure 7.13 Eldar Sætre. Executive vice president Marketing, Processing and Renewable energy

Eldar Sætre
Born: 1956
Position: Executive vice president in Statoil ASA since October 2003, now for Marketing, Processing and Renewable Energy (MPR).
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2013: 25,960
Loans from Statoil: None
Experience: Joined Statoil in 1980. Executive vice president and CFO from October 2003 until December 2010. Has been in his current position since January 2011.
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: Eldar Sætre is a Norwegian citizen and resident in Norway.

Figure 7.14 Lars Christian Bacher. Executive vice president Development and Production International

Lars Christian Bacher
Born: 1964
Position: Executive vice president, Development & Production International (DPI), from 1 September 2012.
External offices: None
Number of shares in Statoil ASA as of 31 December 2013: 18,208
Loans from Statoil ASA: None
Experience: Lars Christian 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 North America (DPNA).
Education: Graduate engineer 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: Lars Christian Bacher is a Norwegian citizen and resident in Norway.

Figure 7.15 William Maloney. Executive vice president Development and Production North America.

William Maloney
Born: 1955
Position: Executive vice president, Development and Production North America (DPNA), in Statoil ASA from 1 January 2011.
External offices: Corporate advisory board (AAPG) & API board member. Member of the National Petroleum Council (NPC) in the US.
Number of shares in Statoil ASA as of 31 December 2013: 31,135.93 (American Depository Receipts)
Loans from Statoil: None
Experience: Held the position of senior vice president for global exploration in International Operations in Statoil from 2002 to 2008. He had a sabbatical period from Statoil from January 2009 until September 2010. He held managerial positions in Shell, Davis Petroleum Corp and Texaco between 1981 and 2002.
Education: Master of science degree in geology from Syracuse University.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.*
Other matters: William Maloney is an American citizen and resident in the United States.

Figure 7.16 John Knight. Executive vice president Global Strategy and Business Development

John Knight
Born: 1958
Position: Executive vice president, Global Strategy and Business Development (GSB), in Statoil ASA from 1 January 2011.
External offices: None
Numbers of shares in Statoil ASA as of 31 December 2013: 57,949
Loans from Statoil ASA: None
Experience: Has held several central managerial positions in International Operations in Statoil since 2002, mainly in business development. Between 1987 and 2002, he 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: 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: John Knight is a British citizen, and resident in England.

Figure 7.17 Tim Dodson. Executive vice president, Exploration

Tim Dodson
Born: 1959
Position: Executive vice president, Exploration (EXP), in Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2013: 19,843
Loans from Statoil ASA: None
Experience: 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: Tim Dodson is a British citizen and resident in Norway.

Figure 7.18 Margareth Øvrum. Executive Vice President Technology, Projects and Drilling

Margareth Øvrum
Born: 1958
Position: Executive vice president in Statoil ASA since September 2004, now for Technology, Projects and Drilling (TPD).
External offices: Member of the board of Atlas Copco AB and Ratos AB.
Number of shares in Statoil ASA as of 31 December 2013: 32,327
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. She 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: Margareth Øvrum is a Norwegian citizen and resident in Norway.

Figure 7.19 Øystein Michelsen. Executive vice president Development and Production Norway

Øystein Michelsen
Born: 1956
Position: Executive vice president, Development and Production Norway (DPN), in Statoil ASA from 10 November 2008 - 31 December 2013.*
External offices: Member of the board of the Norwegian Oil and Gas Association
Number of shares in Statoil ASA as of 31 December 2013: 24,075
Loans from Statoil ASA: None
Experience: Recruited to Hydro's research centre in Porsgrunn in 1981, he was attached to Hydro's oil and energy division from 1985, and was head of the operations unit for Hydro's oil activities from 2004. He has been senior vice president for Statoil's Operations North cluster since 1 October 2007.
Education: Master's degree in applied physics (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim.
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Øystein Michelsen is a Norwegian citizen and resident.

*Effective as from 1 January 2014, Arne Sigve Nylund has been appointed new executive vice president for Development and Production Norway.

Figure 7.20 Arne Sigve Nylund

Arne Sigve Nylund
Born: 1960
Position: Executive vice president in Statoil ASA from 1 January 2014.
External offices: Member of the board of directors of The Norwegian Oil & Gas Association (Norsk Olje & Gass).
Loans from Statoil: None
Experience: Employed by Mobil Exploration Inc. from 1983-1987. Since 1987 he 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: Arne Sigve Nylund is a Norwegian citizen and is resident in Norway.

7.9 Compensation paid to governing bodies

This section describes the compensation paid to the board of directors, the corporate executive committee and the corporate assembly.

In 2013, aggregate compensation totalling NOK 1,008,000 was paid to the members of the corporate assembly, NOK 5,847,000 to the members of the board of directors and NOK 69,167,000 to the members of the corporate executive committee (all in rounded figures).

Detailed information about the individual compensation paid to the members of the board of directors and members of the corporate executive committee in 2013 is provided in the tables below.

Members of the board (in NOK thousand)	Board remuneration	Audit committee	Compensation committee	SSE committee	Total remuneration
Svein Rennemo	682		77		759
Grace Reksten Skaugen	435		112		547
Roy Franklin*	274	61		42	377
Jakob Stausholm	348	193			541
Bjørn Tore Godal	348		77	87	512
Lady Barbara Singer Judge*	274	61			335
Lill Heidi Bakkerud	348			69	417
Morten Svaan*	169	61			230
Einar Arne Iversen*	169				169
Børge Brende**	273			44	317
Maria Johanna Oudeman	491	129			620
Catherine Jeanne Hughes***	238	58			296
James Joseph Mulva***	238			37	275
Stig Lægreid***	178			37	215
Ingrid Elisabeth Di Valerio***	178	59			237
Total	4,643	622	266	316	5,847

* Member until and including 30 June 2013
** Member until and including 15 October 2013
*** Member from 1 July 2013

Management remuneration in 2013 (in NOK thousands)

Members of corporate executive committee	Fixed remuneration: Base pay 1)	Fixed remuneration: LTI 2)	Annual variable pay	Taxable benefits in kind	Taxable compensation	Non-taxable benefits in kind	Estimated pension cost 3)	Estimated present value of pension obligation 4)
Lund Helge	7,596	2,112	3,409	669	13,786	503	4,476	46,369
Reitan Torgrim	3,114	689	1,019	133	4,955		627	16,257
Sjøblom Tove Stuhr [5)]	194			16	210	16	684	18,870
Bacher Lars Christian	2,937	671	634	366	4,608	427	711	15,425
Dodson Timothy	3,432	750	1,297	139	5,618	318	972	24,792
Øvrum Margareth	3,750	840	1,251	194	6,035	108	1,103	43,166
Michelsen Øystein	3,522	838	1,041	334	5,735	191	834	35,993
Sætre Eldar	3,524	836	1,038	367	5,765		1,003	42,360
Maloney William	3,985	2,451	2,733	786	9,955	159	627	
Knight John	5,172	2,426	2,426	754	10,778		1,034	

1) Base pay consists of base salary, holiday allowance and any other administrative benefits.
2) Participants in the Long-term incentive scheme are obliged to invest the net amount in statoil shares with a lock-in period of 3 years. The LTI element is presented the year it is granted. Members of the corporate executive committee employed by non-Norwegian subsidiaries have an 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.
3) 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 2013. Payroll tax is not included. The change to the estimated pension cost is mainly caused by changes to the economic assumptions from 2011 to 2012. Members of the corporate executive committee employed by non-Norwegian subsidiaries have a defined contribution scheme in 2013.
4) The increase to the estimated present value of the pension obligation is mainly due to changes in the underlying mortality assumption.
5) Tove Stuhr Sjøblom served as executive vice president through January 2013.

Statement on remuneration and other terms of employment for Statoil's corporate executive committee

Pursuant to the Norwegian Public Limited Liability Companies Act, section 6-16 a, the board will present the following statement regarding remuneration of Statoil's corporate executive committee to the 2014 annual general meeting:

1. Remuneration policy and concept for the accounting year 2013

1.1 Policy and principles

In general the company's established remuneration principles and concepts will be continued in the accounting year 2014. As described in section 1.2 below, the ongoing evaluation process regarding the general pension scheme in the parent company is expected to conclude in 2014.

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
- reward and recognise delivery and behaviour equally
- differentiate on the basis of responsibilities and performance
- reward both short- and long-term contributions and results

1.2 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 long-term incentive LTI)
- Variable pay
- Benefits (primarily pension, insurance and share savings plan)

Fixed remuneration consists of base salary and a long-term incentive programme. Statoil will continue the established long-term incentive system in the form of fixed compensation with an obligation to invest in Statoil shares for a limited number of senior executives and key professional positions. The purpose of the LTI scheme is alignment with shareholder interests and retention. Members of the corporate executive committee are included in the scheme.

The only variable pay element for parent company executives is the annual variable pay scheme which has a maximum potential of 50% of the fixed remuneration (in line with the governmental guidelines on executive remuneration). The company's performance based variable pay concept will be continued in 2014.

The main benefit programmes applicable to senior executives are the general pension scheme, the insurance scheme and the employee share savings plan. The process of evaluating changes to the general pension scheme in the parent company is expected to be concluded in 2014. This evaluation includes an assessment on the question of replacing the current defined benefit scheme with a defined contribution scheme and the prevailing pension scheme for salaries exceeding 12 times the national insurance basic amount (G).

A revised pension scheme for new members of the corporate executive committee consistent with the governmental guidelines on executive remuneration will be designed and implemented when the changes to the overall pension system have been determined.

Deviations from the general principles outlined below pertaining to two members of the corporate executive committee, implemented with effect as of 1 January 2011, are described in section 3.1 below. 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 "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 long-term incentive system is a fixed, monetary compensation calculated as a portion of the participant's base salary; ranging from 20 - 30 % depending on the individual's position. 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.	In Statoil ASA, LTI is a fixed remuneration element. Participation in the long-term incentive (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 behaviour goals.	The chief executive officer is entitled to an annual variable pay ranging from 0 - 50% of his fixed remuneration. Target value is 25%. Correspondingly, the executive vice presidents have an annual variable pay scheme with a pay-out in the range of 0 - 40%. Target value is 20%.	Achievement of annual performance goals (delivery and behaviour), in order to create long-term and sustainable shareholder value. A balanced scorecard covering goals related to our five strategic objectives (People and organisation, Health, safety and environment, Operations, Market and Finance) are measured and assessed along with individual behaviour goals. One of several goals in the performance contracts of the chief executive officer and chief financial officer is related to the company's relative total shareholder return (TSR). Their annual variable pay is based on an overall assessment of the performance of various targets including but not limited to the company's relative TSR.
Pension & Insurance Schemes	Provide competitive postemployment and other benefits.	The general pension plan is a defined benefit scheme with a pension level amounting to 66 % 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 occupational pension scheme the employment with the company needs to be maintained until the pensionable age.	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] Target value reflects fully satisfactory goal achievement
[2] As outlined above, the company's general pension scheme is subject to revision

1.4 Pension and insurance schemes

The pension schemes for members of the corporate executive committee including the chief executive officer constitute supplementary individual agreements to the company's general pension plan.

Subject to specific terms in his pension agreement of 7 March 2004, the chief executive officer is entitled to a pension amounting to 66 per cent of pensionable salary and a retirement age of 62. The full service period is 15 years.

Two 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, three members of the corporate executive committee in 2013 had an 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.

Pension accruals for pensionable salary above 12 times the national insurance basic amount (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 other benefits in accordance with Statoil's general pension plan including pension from the age of 67 based on the defined benefit arrangement. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

The executive vice presidents employed outside the parent company had in 2013 defined contribution schemes (16 and 20% of base salary in contribution respectively) in accordance with the framework established in their local employment companies. The pension contribution was paid into a separate legal entity.

1.5 Severance pay arrangements

Under the terms of his contract of 7 March 2004, the chief executive officer is entitled to severance payment corresponding to 24 months of base salary in the event of a board resolution to release him from his contract of employment. Severance payment is calculated from the expiry of the notice period of 6 months. The same entitlement applies should the parties agree that the employment will be discontinued and the chief executive officer gives notice pursuant to a written agreement with the board.

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.

1.6 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.

2. Performance management, assessment and results essential for variable pay for 2013

Performance is evaluated in two dimension; business delivery and behaviour. Behaviour goals are based on our core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals. Business delivery is defined through the company's performance framework "Ambition to Action", which addresses strategic objectives, KPIs and actions across the five perspectives People and Organisation, HSE, Operations, Market and Finance. Generally, Statoil believes in setting ambitious targets to inspire and drive strong performance.

In 2013, the main objectives and KPIs for each perspective were as outlined below. Each perspective was in addition supported by comprehensive plans and actions.

Strategic objectives		2013 result assessment
People and organisation	The strategic objectives and actions address global capabilities, learning, innovation, simplification and cost consciousness.	The completion rate of 94% for the people management process People@Statoil[3] remained high. The measured quality of the process and results on competence development are stable.
HSE	The strategic objectives and actions address industry leadership in safety and carbon efficiency.	The positive trend for the serious incident frequency continued and is now at its lowest level ever. There were no serious well incidents, whereas there were too many oil/gas leakages. The investigation following the In Amenas terrorist attack revealed a need for improvements, particularly within the areas of security leadership and processes. Improvement initiatives are in the process of being implemented.
Operations	The strategic objectives and actions address reliable and cost-efficient operations, value-driven technology development and our role as the industrial architect of the Norwegian continental shelf.	Production was as expected, impacted by value creating divestments. Unit production cost remained in the targeted first quartile set against an industry peer group. Efforts to reduce unplanned losses continued.
Market	The strategic objectives and actions address stakeholder trust, value chain optimisation and an exploration driven resource strategy.	In 2013 Statoil delivered the best exploration results in the industry, measured by conventional discovered volume. The company added 1.25 billion barrels of oil equivalent from exploration. The reserve replacement ratio (RRR) was 128%. Organic RRR was 147%, which is a record since 1999. Downstream results ended lower than 2012 mainly due to lower margins on gas sold and lower refining margins.
Finance	The strategic objectives address shareholder return, financial robustness and cost efficiency.	RoACE was in the second quartile measured against an industry peer group, but TSR was in the fourth quartile measured against the same group.

Board assessment of the CEO's performance In its assessment of the CEO's performance and consequently his merit adjustment and annual variable pay for 2013, the board has put emphasis on the improvements within HSE, a solid delivery on production, very strong reserves replacement ratio and world-class exploration results. However, the TSR was below target in 2013 and has affected the board's evaluation of the performance. The investigation following the In Amenas terrorist attack revealed a need for improvements, particularly within the areas of security leadership and processes. However, the CEO and his team demonstrated an exemplary ability to handle the difficult situation, evidenced by the company's response during and after this tragic incident. The Board is satisfied with the identification and initiation of the improvement measures.

[3] *People@Statoil* is Statoil's process for managing people development, deployment, performance and reward.

Before final conclusions of the performance assessment 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 the delivery and behaviour 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.

3. Execution of the remuneration policy and principles in 2013

3.1 Deviations from the Statement on Executive remuneration 2013

Two members of the executive committee have variable pay schemes deviating from the description in section 1.2 above. The individuals in question are employed by Statoil Gulf Services LLC in Houston and Statoil Global Employment Company Ltd. in London. These schemes entail a framework for variable pay of 75-100% of the base salary for each of the elements (annual variable pay and long term Incentive). The long-term incentive is performance based. The contracts also include 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 in alignment with the market, but not market leading for positions at this level at the respective locations.

3.2 Development in actual remuneration

During the last five-year period the average annual framework for merit increase in the parent company has been 3.25%. During the same period the CEO's average annual base salary increase has been 2.75%. As of 1 January 2014 the base salary increase for CEO was 2.5%. The annual variable pay for 2013 was 35% of the fixed remuneration. The base salary increase and the variable pay reflect the board's overall assessment of his performance as outlined in Section 2 above. On average over the last five years, the annual variable pay has been 31%. This average was influenced by the fact that the maximum variable pay potential for 2009 was reduced by 50 % as a consequence of the financial crisis.

3.3 Changes to the Corporate Executive Committee in 2013

A change to the corporate organisation structure was decided in 2012, leading to the discontinuation of the position as Executive Vice President and Chief of Staff. Effective 1 February 2013, Tove Stuhr Sjøblom was assigned to the role as Senior Vice President, Sub-Saharan Africa in Development and Production International.

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 alone 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.

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 2013	As of 13 March 2014
Members of the corporate executive committee		
Helge Lund	61,151	61,593
Torgrim Reitan	20,301	20,994
Margareth Øvrum	32,327	33,531
Eldar Sætre	25,960	25,960
Øystein Michelsen*	24,075	N/A
Lars Christian Bacher	18,208	19,229
Tim Dodson	19,843	20,754
William Maloney	31,135**	31,960**
John Knight	51,349	53,136
Arne Sigve Nylund***	N/A	4,785
Members of the board of directors		
Svein Rennemo	10,000	10,000
Grace Reksten Skaugen	400	400
Bjørn Tore Godal	0	0
Jakob Stausholm	32,600	32,600
Maria Johanna Oudeman	0	0
James Mulva	0	0
Catherine Hughes	0	0
Lill-Heidi Bakkerud	330	330
Ingrid Elisabeth di Valerio	1,778	1,962
Stig Lægreid	1,519	1,519

* Øystein Michelsen was a member of the corporate executive committee until 31 December 2013.
** American Depository Receipts (ADR)
*** Arne Sigve Nylund has been a member of the corporate executive committee since 1 January 2014.

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2013 and as of 13 March 2014. In aggregate, members of the corporate assembly owned a total of 15,740 shares as of 31 December 2013 and a total of 17,106 shares as of 13 March 2013. 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. 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 2013
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, for the fiscal year 2013 and 2012 (from 15 May), and Ernst & Young for the fiscal year 2011 and until 15 May 2012.

Auditor's remuneration (in NOK million, excluding VAT)	For the year ended 31 December 2013	2012	2011
Audit fees KPMG (principal accountant 2013 and 2012, as from 15 May 2012)	38	22	-
Audit fees Ernst & Young (principal accountant 2011)	-	22	63
Audit-related fees (KPMG for 2013 and 2012, Ernst & Young for 2011)	8	9	7
Tax fees (KPMG for 2013 and 2012, Ernst & Young for 2011)	0	2	0
All other fees (KPMG for 2013 and 2012, Ernst & Young for 2011)	0	2	3
Total	46	57	73

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.

In addition to the figures in the table above, the audit fees and audit-related fees relating to Statoil-operated licences paid to KPMG and Ernst & Young for the years 2013, 2012 and 2011 amounted to NOK 6 million, NOK 7 million and NOK 9 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 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, tax and 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 (1992) 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 2013 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, 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 2013 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.

Changes in internal control over financial reporting
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.

8 Consolidated financial statements Statoil

CONSOLIDATED STATEMENT OF INCOME

		For the year ended 31 December		
(in NOK billion)	Note	2013	2012	2011
Revenues		619.4	704.3	645.4
Net income from associated companies		0.1	1.7	1.3
Other income	4	17.8	16.0	23.3
Total revenues and other income	3	637.4	722.0	670.0
Purchases [net of inventory variation]		(307.5)	(364.5)	(320.1)
Operating expenses		(75.0)	(61.2)	(59.7)
Selling, general and administrative expenses		(9.2)	(11.1)	(13.2)
Depreciation, amortisation and net impairment losses	11, 12	(72.4)	(60.5)	(51.4)
Exploration expenses	12	(18.0)	(18.1)	(13.8)
Net operating income	3	155.5	206.6	211.8
Net financial items	8	(17.0)	0.1	2.0
Income before tax		138.4	206.7	213.8
Income tax	9	(99.2)	(137.2)	(135.4)
Net income		39.2	69.5	78.4
Attributable to equity holders of the company		39.9	68.9	78.8
Attributable to non-controlling interests		(0.6)	0.6	(0.4)
Basic earnings per share (in NOK)	10	12.53	21.66	24.76
Diluted earnings per share (in NOK)	10	12.50	21.60	24.70

The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK billion)	Note	For the year ended 31 December 2013	2012	2011
Net income		39.2	69.5	78.4
Actuarial gains (losses) on defined benefit pension plans	19	(5.9)	5.5	(7.4)
Income tax effect on income and expense recognised in OCI		1.5	(1.5)	2.0
Items that will not be reclassifed to statement of income		(4.4)	4.0	(5.4)
Foreign currency translation differences		22.9	(11.9)	6.1
Change in fair value of available for sale financial assets		0.0	0.0	(0.2)
Items that may be subsequently reclassified to statement of income		22.9	(11.9)	5.9
Other comprehensive income		18.5	(7.9)	0.5
Total comprehensive income		57.7	61.6	78.9
Attributable to equity holders of the company		58.3	61.0	79.3
Attributable to non-controlling interests		(0.6)	0.6	(0.4)

CONSOLIDATED BALANCE SHEET

(in NOK billion)	Note	At 31 December 2013	2012
ASSETS			
Property, plant and equipment	11	487.4	439.1
Intangible assets	12	91.5	87.6
Investments in associated companies		7.4	8.3
Deferred tax assets	9	8.2	3.9
Pension assets	19	5.3	9.4
Derivative financial instruments	25	22.1	33.2
Financial investments	13	16.4	15.0
Prepayments and financial receivables	13	8.5	4.9
Total non-current assets		646.8	601.4
Inventories	14	29.6	25.3
Trade and other receivables	15	81.8	74.0
Derivative financial instruments	25	2.9	3.6
Financial investments	13	39.2	14.9
Cash and cash equivalents	16	85.3	65.2
Total current assets		238.8	183.0
Total assets		885.6	784.4
EQUITY AND LIABILITIES			
Shareholders' equity		355.5	319.2
Non-controlling interests		0.5	0.7
Total equity	17	356.0	319.9
Finance debt	18, 22	165.5	101.0
Deferred tax liabilities	9	71.0	81.2
Pension liabilities	19	22.3	20.6
Provisions	20	101.7	95.5
Derivative financial instruments	25	2.2	2.7
Total non-current liabilities		362.7	301.0
Trade and other payables	21	95.6	81.8
Current tax payable		52.8	62.2
Finance debt	18	17.1	18.4
Derivative financial instruments	25	1.5	1.1
Total current liabilities		166.9	163.5
Total liabilities		529.6	464.5
Total equity and liabilities		885.6	784.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK billion)	Share capital	Additional paid-in capital	Retained earnings	Available for sale financial assets	Currency translation adjustments	Shareholders' equity	Non-controlling interests	Total equity
At 31 December 2010	8.0	40.8	164.9	0.2	5.6	219.5	6.9	226.4
Net income for the period			78.8			78.8	(0.4)	78.4
Other comprehensive income			(5.4)	(0.2)	6.1	0.5		0.5
Dividends paid			(19.9)			(19.9)		(19.9)
Other equity transactions		(0.1)	0.1			0.0	(0.2)	(0.2)
At 31 December 2011	8.0	40.7	218.5	0.0	11.7	278.9	6.3	285.2
Net income for the period			68.9			68.9	0.6	69.5
Other comprehensive income			4.0		(11.9)	(7.9)		(7.9)
Dividends paid			(20.7)			(20.7)		(20.7)
Other equity transactions		(0.1)	0.1			0.0	(6.2)	(6.2)
At 31 December 2012	8.0	40.6	270.8	0.0	(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
Dividends paid			(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	0.0	22.7	355.5	0.5	356.0

Refer to note 17 *Shareholders' equity*.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	For the year ended 31 December 2013	2012	2011
Income before tax		**138.4**	206.7	213.8
Depreciation, amortisation and net impairment losses	11,12	**72.4**	60.5	51.4
Exploration expenditures written off		**3.1**	3.1	1.5
(Gains) losses on foreign currency transactions and balances		**4.8**	3.3	4.2
(Gains) losses on sales of assets and other items	4	**(19.9)**	(21.9)	(27.4)
(Increase) decrease in non-current items related to operating activities		**8.8**	(7.4)	(0.7)
(Increase) decrease in net derivative financial instruments	25	**11.7**	(1.1)	(12.8)
Interest received		**2.1**	2.6	2.7
Interest paid		**(2.5)**	(2.5)	(3.1)
Taxes paid		**(114.2)**	(119.9)	(112.6)
Adjustments for working capital items				
(Increase) decrease in inventories		**(1.1)**	0.8	(4.1)
(Increase) decrease in trade and other receivables		**(11.9)**	10.8	(14.3)
Increase (decrease) in trade and other payables		**9.7**	(7.0)	20.4
Cash flows provided by operating activities		**101.3**	128.0	119.0
Additions through business combinations		**0.0**	0.0	(25.7)
Additions to property, plant and equipment		**(103.3)**	(94.8)	(84.2)
Capitalised interest paid		**(1.1)**	(1.2)	(0.9)
Exploration expenditures capitalised and additions in other intangibles		**(10.0)**	(16.4)	(7.2)
(Increase) decrease in financial investments		**(23.2)**	(12.1)	3.8
(Increase) decrease in non-current loans granted and other non-current items		**0.0**	(1.9)	(0.5)
Proceeds from sales of assets and businesses	4	**27.1**	29.8	29.8
Cash flows used in investing activities		**(110.4)**	(96.6)	(84.9)
New finance debt		**62.8**	13.1	10.1
Repayment of finance debt		**(7.3)**	(12.2)	(7.4)
Dividends paid	17	**(21.5)**	(20.7)	(19.9)
Net current finance debt and other		**(7.3)**	1.6	4.5
Cash flows provided by (used in) financing activities		**26.6**	(18.2)	(12.7)
Net increase (decrease) in cash and cash equivalents		**17.5**	13.2	21.4
Effect of exchange rate changes on cash and cash equivalents		**2.9**	(1.9)	(0.2)
Cash and cash equivalents at the beginning of the year (net of overdraft)	16	**64.9**	53.6	32.4
Cash and cash equivalents at the end of the year (net of overdraft)	16	**85.3**	64.9	53.6

Cash and cash equivalents include a net bank overdraft rounded to zero at 31 December 2013, NOK 0.3 billion at 31 December 2012 and NOK 1.7 billion at 31 December 2011.

8.1 Notes to the Consolidated financial statements

8.1.1 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.

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.

Statoil ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA).

All the Statoil group's oil and gas activities and net assets on the Norwegian continental shelf (NCS) 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 year ended 31 December 2013 were authorised for issue in accordance with a resolution of the board of directors on 14 March 2014.

8.1.2 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).

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.

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 interpretations issued but not yet adopted
At the date of these Consolidated financial statements, the following standard amendments and interpretation applicable to Statoil have been issued, but were not yet effective, and will be adopted by Statoil on 1 January 2014. The amendments and interpretation will not materially impact Statoil's financial statements upon adoption. They require retrospective implementation, but are immaterial in regard to the impact on Statoil's accounts for previous reporting periods.

- The amendments to IAS 32 *Financial Instruments: Presentation*, issued in December 2011, clarify the requirements for offsetting financial assets and financial liabilities in the financial statements.
- IFRIC 21 *Levies*, issued in May 2013, addresses the accounting for liabilities to pay levies that are within the scope of IAS 37 *Provisions, contingent liabilities and contingent assets*.

At the date of these Consolidated financial statements the following further standards and amendments applicable to Statoil have been issued, but were not yet effective nor adopted by Statoil:

- IFRS 9 *Financial Instruments*, issued for the first part in November 2009, for the second part in October 2010, and for the third part in November 2013, and with amendments issued in December 2011, covers the classification and measurement of financial assets and financial liabilities as well as hedge accounting. The IASB has not yet established a mandatory effective date for IFRS 9, which also includes amendments to various other IFRSs that will be effective from the same date. Statoil has not yet determined its adoption date for the standard and is still evaluating its potential impact.
- *The Annual Improvements* to IFRSs *2010 - 2012 Cycle* and *2011 - 2013 Cycle* both were issued in December 2013, and include amendments to a number of accounting standards, and are effective after 1 July 2014 or for annual periods beginning after that date, depending on the standard involved. Statoil is still evaluating the potential impact of the Improvement Cycle amendments.

Other standards, amendments and interpretations currently in issue but not yet effective are not expected to be relevant to Statoil's Consolidated financial statements upon adoption.

Significant changes in accounting policies in the current period
The accounting standards and standard amendments applicable to Statoil and listed in the following two paragraphs were implemented on 1 January 2013. None of these standards and amendments has materially impacted Statoil's Consolidated financial statements upon implementation, although certain line items have been affected. Except for IFRS 13 *Fair Value Measurement,* the standards and amendments required retrospective implementation, but were assessed to be immaterial as regards their impact on Statoil's financial statements for previous reporting periods. Consequently prior periods' information has not been restated to reflect the impact of the implemented standards and amendments. The following paragraphs describe relevant information directly related to the implementation in Statoil's financial statements. Description of the actual principles applied by Statoil in accordance with standards and amendments implemented as of 1 January 2013 are included in the relevant principle specific sections of this note.

IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements* and IFRS 12 *Disclosure of Interests in Other Entities*, their respective transition guidance amendments and the amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures* were implemented simultaneously by Statoil. EU endorsement of these standards and amendments establishes an effective date of 1 January 2014, however, Statoil has in this instance elected early adoption of the standards as of 1 January 2013, which is the IASB's effective date of the standards. Adoption of IFRS 10 has not led to significant changes in entities deemed to be controlled by Statoil, nor has Statoil identified significant entities or activities within the scope of IFRS 11 that are accounted for differently under the new standard.

IFRS 13 *Fair Value Measurement*, the amendments to IAS 19 *Employee benefits,* the amendments to IAS 1 *Presentation of Financial Statements*, and the *Annual Improvements to IFRSs (2009 - 2011)* have also been implemented without material impact for these Consolidated financial statements. Disclosures as required by the amendments to IFRS 7 *Financial Instruments: Disclosures* are included in Note 5 *Financial risk management*.

There have been no other significant accounting policy changes in 2013 compared to the annual financial statements for 2012. Relevant sections of this note have been updated to further clarify Statoil's accounting policies in certain areas commented upon by the Norwegian Financial Supervisory Authority (the FSA) in their review of Statoil's Consolidated financial statements for 2012. Reference is made to Note 28 *Subsequent events* for further information on the FSA review.

Changes in accounting policies in 2012
In 2012 Statoil changed its policy for classification of short-term financial investments with less than three months to maturity from *Financial investments* to *Cash and cash equivalents* in the balance sheet. At the same time, Statoil changed its policy for presentation of changes in current financial investments from *Cash flows provided by operating activities* to *Cash flows used in investing activities* in the statement of cash flows. The policy change was retrospectively applied in the 2011 Consolidated financial statements. As a consequence, the line item *Net increase (decrease) in cash and cash equivalents* in the 2011 Consolidated statement of cash flows changed from NOK 10.0 billion to NOK 21.4 billion primarily caused by an increase in *Cash flows provided by operating activities* from NOK 111.5 billion to NOK 119.0 billion and a decrease in *Cash flows used in investing activities* from NOK 88.7 billion to NOK 84.9 billion. *Cash and cash equivalents at the beginning of the year (net of overdraft)* changed from NOK 29.1 billion to NOK 32.4 billion and *Cash and cash equivalents at the end of the year (net of overdraft)* changed from NOK 38.8 billion to NOK 53.6 billion.

Basis of consolidation
Subsidiaries
The Consolidated financial statements include the accounts of Statoil ASA and its 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
An arrangement to which Statoil is party is defined as jointly controlled when the sharing of control is contractually agreed, which exists only when 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 and the balance sheet 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 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 OCI.

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 ASA sells, in its own name, but for the Norwegian State's account and risk, the State's production of natural gas. This sale, and related expenditures refunded by the Norwegian State, are presented net in the Consolidated financial statements. Sales made by Statoil subsidiaries in their own name, and related expenditure, are however presented gross in the Consolidated financial statements where the applicable subsidiary is considered the principal when selling natural gas on behalf of the Norwegian State. In accounting for these sales activities, the Norwegian State's share of profit or loss is reflected in Statoil's *Selling, general and administrative expenses* as expenses or reduction of expenses, respectively.

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 virtually certain amount 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.

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 substantially 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 and similar facts and circumstances.

A petroleum tax, currently levied at a rate of 50% (51% from 2014), is levied on profits derived from petroleum production and pipeline transportation on the NCS. The petroleum tax is applied to relevant income in addition to the standard 28% income tax (27% from 2014), resulting in a 78% marginal tax rate on income subject to Norwegian petroleum tax. The basis for computing the petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible against the petroleum tax, and a tax-free allowance (uplift) is computed on the basis of the original capitalised cost of offshore production installations at a rate of 5.5% per year. The uplift may be deducted from taxable income for a period of four years, starting in the year in which the capital expenditures are incurred. The uplift benefit is recognised when the deduction is included in the current year tax return and impacts taxes payable. Unused uplift may be carried forward indefinitely.

Oil and gas exploration 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. If, following the evaluation, the exploratory well has not found proved reserves, the previously capitalised costs are evaluated for derecognition or tested for impairment. Geological and geophysical costs and other exploration 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), when the farmee correspondingly undertakes to fund carried interests as part of the consideration, 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.

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, and, for qualifying assets, borrowing costs. Property, plant and equipment include assets acquired 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 reliably measurable.

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 development 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 are depreciated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. 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.

Expenses related to the drilling of exploration wells are initially capitalised as intangible assets pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. This evaluation is normally finalised within one year after well completion. Exploration wells that discover potentially economic quantities of oil and natural gas remain capitalised as intangible assets during the evaluation phase of the find, see further information under the Oil and gas exploration and development expenditures section above.

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
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 to be 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. Frequently the recoverable amount of an asset proves to be Statoil's estimated value in use, which 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 plans. Statoil's long-term plans are reviewed by corporate management and updated at least annually. The plans cover a 10-year period and reflect expected production volumes for oil and natural gas in that period. For assets and CGUs with an expected useful life or timeline for production of expected reserves extending beyond 10 years, 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.

Impairments are reversed, as applicable, to the extent that conditions for impairment are no longer present. 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. For defined benefit schemes, 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 benefits 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 net defined benefit liability (asset). The interest cost element is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The interest income on plan assets is determined by applying the discount rate to the opening present value of the plan assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid 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 net interest income and actual return is recognised in OCI.

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.

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 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 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.

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. Refining and processing plants that are not limited by licence periods are deemed to have indefinite lives and, in consequence, no ARO has been recognised.

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. 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 ongoing 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 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, 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.

8.1.3 Segments

Statoil's operations are managed through the following operating segments: Development and Production Norway (DPN), Development and Production North America (DPNA), Development and Production International (DPI), Marketing, Processing and Renewable Energy (MPR) and Other. The Fuel and Retail segment (FR) was sold on 19 June 2012.

The development and production operating segments, which are organised based on a regional model with geographical clusters or units, are responsible for the commercial development of the oil and gas portfolios within their respective geographical areas: DPN on the Norwegian continental shelf, DPNA in North America including offshore and onshore activities in the USA and Canada and DPI worldwide outside of North America and Norway.

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 MPR 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, wind parks and other activities within renewable energy.

Statoil reports its business through reporting segments which correspond to the operating segments, except for the operating segments DPI and DPNA 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 and the methods of distribution.

The Other reporting segment includes activities within Global Strategy and Business Development, Technology, Projects and Drilling and the Corporate staffs and services.

In the second quarter 2012, Statoil divested its FR segment through Statoil ASA's sale of its 54% shareholding in Statoil Fuel & Retail ASA (SFR). A gain of NOK 5.8 billion was recognised on the sale. In the segment reporting, the gain has been presented in the FR segment as Revenues and other income - third party. The FR segment marketed fuel and related products principally to retail consumers.

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 2013, 2012 and 2011 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 associated companies is excluding movements due to changes in asset retirement obligations.

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Other	Fuel and Retail	Eliminations	Total
Year ended 31 December 2013							
Revenues third party and Other income	9.4	16.5	610.3	1.0	-	-	637.2
Revenues inter-segment	192.7	65.4	1.0	0.1	-	(259.1)	0.0
Net income (loss) from associated companies	0.1	0.0	0.1	0.0	-	-	0.1
Total revenues and other income	202.2	81.9	611.4	1.0	-	(259.1)	637.4
Net operating income	137.1	16.4	2.6	(1.1)	-	0.4	155.5
Significant non-cash items recognised							
- Depreciation and amortisation	31.6	29.8	2.7	1.2	-	-	65.4
- Provisions	0.8	4.6	4.1	0.0	-	-	9.5
- Net impairment losses (reversals)	0.6	2.1	4.3	0.0	-	-	7.0
- Unrealised (gain) loss on commodity derivatives	5.6	0.0	(0.1)	0.0	-	-	5.5
- Exploration expenditures written off	0.3	2.8	0.0	0.0	-	-	3.1
Investments in associated companies	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
Additions to PP&E, intangibles and associated companies	57.3	52.9	5.9	1.3	-	-	117.4

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Other	Fuel and Retail	Eliminations	Total
Year ended 31 December 2012							
Revenues third party and Other income	7.7	24.3	646.8	1.3	40.2	-	720.3
Revenues inter-segment	213.0	54.5	22.2	0.0	1.5	(291.2)	0.0
Net income (loss) from associated companies	0.1	1.2	0.4	0.0	0.0	-	1.7
Total revenues and other income	220.8	80.0	669.4	1.3	41.7	(291.2)	722.0
Net operating income	161.7	21.5	15.5	2.6	6.9	(1.6)	206.6
Significant non-cash items recognised							
- Depreciation and amortisation	29.2	26.2	2.4	0.9	0.6	-	59.3
- Net impairment losses (reversals)	0.6	0.0	0.6	0.0	0.0	-	1.2
- Unrealised (gain) loss on commodity derivatives	1.4	0.0	1.8	0.0	0.0	-	3.2
- Exploration expenditures written off	0.8	2.3	0.0	0.0	0.0	-	3.1
Investments in associated companies	0.2	4.8	3.2	0.1	-	-	8.3
Non-current segment assets	235.4	248.3	38.5	4.5	-	-	526.7
Non-current assets, not allocated to segments							66.4
Total non-current assets							601.4
Additions to PP&E, intangibles and associated companies	48.6	54.6	6.2	3.0	0.9	-	113.3

(in NOK billion)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Other	Fuel and Retail	Eliminations	Total
Year ended 31 December 2011							
Revenues third party and Other income	7.9	25.0	564.1	1.0	70.8	-	668.8
Revenues inter-segment	204.2	44.3	45.7	0.0	2.9	(297.1)	0.0
Net income (loss) from associated companies	0.1	0.9	0.2	0.1	0.0	-	1.3
Total revenues and other income	212.2	70.2	610.0	1.1	73.7	(297.1)	670.1
Net operating income	152.7	32.8	24.8	(0.3)	1.9	(0.1)	211.8
Significant non-cash items recognised							
- Depreciation and amortisation	29.5	15.9	2.8	0.8	1.2	-	50.2
- Net impairment losses (reversals)	0.0	(2.1)	3.3	0.0	0.0	-	1.2
- Unrealised (gain) loss on commodity derivatives	(5.6)	0.0	(3.6)	0.0	0.0	-	(9.2)
- Exploration expenditures written off	1.0	0.5	0.0	0.0	0.0	-	1.5
Investments in associated companies	0.2	5.5	2.7	0.8	-	-	9.2
Non-current segment assets	211.6	239.4	34.5	4.0	10.8	-	500.3
Non-current assets, not allocated to segments							61.0
Total non-current assets							570.5
Additions to PP&E, intangibles and associated companies	41.4	84.4	4.6	1.7	1.5	-	133.6

Effective from the fourth quarter of 2013, upstream revenues in the DPI segment originating from the USA are reported net of royalty interest. This change does not result in a change in the *Net operating income*. Historical information has been aligned to the current presentation.

In 2013 Statoil recognised impairment losses related to refinery assets in the MPR segment of NOK 4.3 billion. The basis for the impairment losses is value in use estimates triggered by lower future expected refining margins. The impairment losses have been presented as Net impairment losses (reversals).

In 2011 Statoil recognised impairment losses related to refinery assets in the MPR segment of NOK 3.8 billion. The basis for the impairment losses was value in use estimates triggered by lower future expected refining margins. The impairment losses have been presented as Net impairment losses (reversals).

In 2011 Statoil also recognised a reversal of impairment losses related to assets in the Gulf of Mexico in the DPI segment of NOK 2.6 billion. The basis for the reversal was value in use estimates triggered by changes in cost estimates and market conditions.

See note 4 *Acquisitions and dispositions* for information on gains and losses on transactions that affect the different segments.

See note 20 *Provisions* for information on provisions that have influenced the segments for DPN and MPR.

See note 23 *Other commitments and contingencies* for information on contingencies that have influenced the DPI segment.

Geographical areas

Statoil has business operations in 33 countries. When attributing revenues from third parties to the country of the legal entity executing the sale, Norway constitutes 76%, and the USA constitutes 15%.

Non-current assets by country

(in NOK billion)	At 31 December 2013	2012	2011
Norway	269.6	258.7	249.2
USA	159.2	134.6	112.6
Angola	45.9	42.5	43.6
Brazil	24.5	23.2	26.0
Canada	19.9	17.2	17.3
Azerbaijan	19.0	16.7	17.8
UK	13.6	11.1	8.9
Algeria	9.0	8.7	9.6
Other countries	25.6	22.3	24.5
Total non-current assets*	586.3	535.0	509.5

*Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Crude oil	321.5	367.2	315.0
Refined products	118.9	140.9	128.8
Natural gas	113.2	118.5	98.9
Natural gas liquids	64.5	65.7	62.3
Other	1.3	12.0	40.4
Total revenues	619.4	704.3	645.4

8.1.4 Acquisitions and dispositions

2013

Sale of interests in exploration and production licences on the Norwegian continental shelf to Wintershall
In July 2013 a sales transaction with Wintershall, entered into in October 2012, for certain ownership interests in licences on the Norwegian continental shelf (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 Development and Production Norway (DPN) segment in Revenues third party and Other income. The transaction was tax exempt under the rules in the Norwegian petroleum tax system. Proceed from the sale was 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, entered into in August 2013, 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 Development and Production International (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 system. Proceed from the sale was NOK 15.9 billion.

Agreement for sale of interests in the Shah Deniz and the South Caucasus Pipeline with SOCAR and BP
In December 2013 Statoil entered into an agreement with SOCAR and BP to divest a 10% working interest in the Shah Deniz and the South Caucasus Pipeline reducing its current 25.5% working interest to 15.5%. SOCAR and BP will pay a cash consideration of NOK 8.8 billion (USD 1.45 billion). The transactions will be recognised in the Marketing, Processing and Renewable Energy (MPR) and DPI segments at the time of closing, which is expected to be in the first half of 2014. Statoil expects to recognise a gain from the transactions in the range of NOK 5.5 to 7.0 billion, to be adjusted for activity between 1 January 2014 and the transaction date.

2012

Sale of interests in exploration and production licences on the Norwegian continental shelf

In April 2012 Statoil closed an agreement with Centrica, entered into in November 2011, to sell interests in certain licences on the NCS for a total consideration of NOK 8.6 billion. The consideration included a cash payment of NOK 7.1 billion and a contingent element relating to production in a four year period, capped at NOK 0.6 billion. A gain of NOK 7.5 billion was recognised in the DPN segment in the second quarter 2012 and presented as Revenues third party and Other income. The net book value of the assets taken over by Centrica was NOK 2.0 billion. The transaction was tax exempt under the rules in the Norwegian petroleum tax system and the gain included a release of deferred tax liabilities of NOK 0.9 billion related to the transaction.

Divestment of shares in Statoil Fuel & Retail ASA

On 19 June 2012 Statoil ASA sold its 54% shareholding in Statoil Fuel & Retail ASA (SFR) to Alimentation Couche-Tard for a cash consideration of NOK 8.3 billion. Until the transaction date SFR was fully consolidated in the Statoil group with a 46% non-controlling interest. Statoil recognised a gain of NOK 5.8 billion on the transaction, presented as *Other income* in the Consolidated financial statements. The gain was tax exempt and presented in the Fuel and Retail segment. The net book value of the assets derecognised as part of the divestment was NOK 7.5 billion.

Acquisition of mineral right leases in the Marcellus shale formation in the United States

In December 2012 Statoil closed an agreement to acquire mineral right leases covering 70,000 net acres in the Marcellus shale area in the northeastern part of the United States (US). Statoil became the operator of the licences and holds a 100% working interest in these mineral right leases. The transaction was accounted for as an asset acquisition within the DPI segment, with a total consideration of NOK 3.3 billion (USD 0.6 billion).

2011

Acquisition of Brigham Exploration Company

On 17 October 2011, Statoil and Brigham Exploration Company (Brigham) entered into an agreement for Statoil to acquire all outstanding shares of Brigham through an all-cash tender offer. Brigham was an independent exploration, development and production company and was listed on the NASDAQ in the US before the acquisition. It explored for, developed and produced US domestic onshore crude oil and natural gas reserves. Brigham's exploration and development activities were focused in the areas of the Williston Basin, targeting primarily the Bakken and Three Forks formations in North Dakota and Montana.

Statoil obtained control over Brigham on 1 December 2011, which was the acquisition and valuation date for purchase price allocation (PPA) purposes. At year end 2011, Statoil had obtained ownership of all shares in Brigham. The total cost of the business combination was NOK 26.0 billion. The acquisition was accounted for as a business combination using the acquisition method, where the acquired assets and liabilities were measured at fair value at the date of acquisition. The acquisition was recognised in the DPI segment. The fair value of net identifiable assets of Brigham was NOK 19.1 billion, consisting of total assets of NOK 34.3 billion and total liabilities of NOK 15.2 billion. In addition, goodwill of NOK 6.9 billion was recognised from the transaction. The goodwill was attributed to Statoil's US onshore operations on the basis of expected synergies and other benefits to Statoil from Brigham's assets and activities and was not deductible for tax purposes. The 2011 Consolidated financial statements included results of Brigham for the one-month period from the acquisition date.

Acquisition of exploration rights offshore Angola

On 20 December 2011 Statoil was awarded operatorship and a 55% share of blocks 38 and 39 and partner position with 20% interests in blocks 22, 25 and 40 in the Kwanza basin offshore Angola. The joint ventures were sat up as production sharing agreements (PSAs) in which the national oil company of Angola, Sonangol, participated with a carried interest of 30% in all five blocks during the exploration phase. By entering into the PSAs Statoil incurred total future commitments of NOK 8.4 billion (USD 1.4 billion), which included signature bonuses and minimum work commitments for all the blocks. As at 31 December 2011 a total of NOK 5.2 billion was recognised in the DPI segment and presented as *Intangible assets*.

Sale of interests in Gassled, Norway

On 5 June 2011 Statoil entered into an agreement with Solveig Gas Norway AS to sell a 24.1% ownership interest in the Gassled joint venture (Gassled). Statoil continued to hold a 5% interest in the joint venture after the divestment date 30 December 2011. Solveig Gas Norway AS paid a consideration of NOK 13.9 billion in cash in January 2012 for the 24.1% ownership interest in the joint venture. The transaction was principally tax exempt under the rules in the Norwegian petroleum tax system, however, a portion was taxable under the ordinary Norwegian tax system. Statoil recognised a pre-tax gain of NOK 8.4 billion from the transaction in the fourth quarter 2011, which included a release of deferred tax liabilities related to the tax exempted portion of the transaction. The transaction was recognised in the MPR segment and presented as Revenues third party and Other income.

8.1.5 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 identifying, evaluating and managing risk in all activities using a top-down 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 hedges inherent in Statoil's portfolio. Simply 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 co-ordinated 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-Wide Risk Management and proposing appropriate measures to adjust risk at the corporate level. The committee meets at least six times per year and regularly receives 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, defined as having a time horizon of six months or more, are managed at the corporate level while short-term exposures are managed at segment and lower levels according to trading strategies and mandates approved by Statoil's corporate risk committee.

For the marketing of Statoil's 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
Commodity price risk represents Statoil's most important short-term market risk. 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 swaps 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 NOK against USD. Statoil manages its currency risk from operating activities with USD as the functional 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 are mainly 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, EUR and GBP). 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. During 2013 Statoil adopted a higher share of fixed interest rate exposure on its bond debt. 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. During 2013 Statoil's overall liquidity was further strengthened.

The main cash outflows are the annual dividend payment 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 3.0 billion, supported by 20 core banks, maturing in 2017. The facility supports secure access to funding, supported by the best available short-term rating. It has not been drawn.

Statoil raises debt in all major capital markets (USA, Europe and Japan) for long-term funding purposes. The policy is to have a smooth maturity profile with repayments not exceeding five per cent of capital employed in any year for the nearest five years. Statoil's non-current financial liability has a weighted average maturity of approximately ten 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)	2013	2012
Due within 1 year	103.6	102.8
Due between 1 and 2 years	30.5	28.6
Due between 3 and 4 years	41.7	21.0
Due between 5 and 10 years	71.0	44.9
Due after 10 years	94.4	55.0
Total specified	341.2	252.3

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. In addition, Statoil evaluates any past payment performance, the counterparties' size and business diversification and the inherent industry risk. 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 and regularly reviewed with regard to changes in market conditions.

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. For bank guarantees, only investment grade international banks are accepted as counterparties.

Statoil has pre-defined limits for the absolute credit risk level allowed at any given time on Statoil's portfolio level 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 that are neither past due nor impaired split by Statoil's assessment of the counterparty's credit risk. 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 2013				
Investment grade, rated A or above	0.9	17.2	12.5	1.2
Other investment grade	0.8	45.8	9.3	1.6
Non-investment grade or not rated	2.8	12.6	0.3	0.1
Total financial assets	4.5	75.5	22.1	2.9
At 31 December 2012				
Investment grade, rated A or above	0.9	16.4	17.9	1.6
Other investment grade	0.2	26.0	15.3	1.9
Non-investment grade or not rated	1.4	21.3	0.0	0.1
Total financial assets	2.5	63.7	33.2	3.6

At 31 December 2013, NOK 7.4 billion of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2012, NOK 12.4 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 2013, NOK 2.0 billion presented as liabilities do not meet the criteria for offsetting. At 31 December 2012, NOK 2.5 billion was not offset. The collateral received and the amounts not offset from derivative financial instrument liabilities, reduces 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.

8.1.6 Remuneration

	For the year ended 31 December		
(in NOK billion, except average number of man-labour years)	2013	2012	2011
Salaries	23.5	22.7	21.1
Pension costs	4.6	(0.6)	3.8
Payroll tax	3.4	3.3	3.3
Other compensations and social costs	2.5	2.8	2.5
Total payroll costs	34.0	28.2	30.7
Average number of man-labour years	23,115	26,728	29,378

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil operated licences on an hours incurred basis.

The negative pension cost in 2012 was primarily caused by a curtailment gain recognised on the basis of Statoil's discontinuance of the supplementary (gratuity) part of the early retirement scheme. For further information, 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:

	For the year ended 31 December		
(in NOK million)	2013	2012	2011
Current employee benefits	77.7	81.1	59.4
Post-employment benefits	12.1	13.6	12.0
Other non-current benefits	0.1	0.1	0.1
Share based payment benefits	1.2	1.3	1.0
Total	91.1	96.1	72.5

At 31 December 2013, 2012 and 2011, 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, 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 0.6 billion, NOK 0.5 billion and NOK 0.5 billion related to the 2013, 2012 and 2011 programs, respectively. For the 2014 program (granted in 2013), the estimated compensation expense is NOK 0.6 billion. At 31 December 2013, the amount of compensation cost yet to be expensed throughout the vesting period is NOK 1.2 billion.

8.1.7 Other expenses

Auditor's remuneration

	For the year ended 31 December		
(in NOK million, excluding VAT)	2013	2012	2011
Audit fee	38	44	63
Audit related fee	8	9	7
Tax fee	0	2	0
Other service fee	0	2	3
Total	46	57	73

In addition to the figures in the table above, the audit fees and audit related fees related to Statoil operated licences amount to NOK 6 million, NOK 7 million and NOK 9 million for 2013, 2012 and 2011, respectively.

Research and development expenditures
Research and development (R&D) expenditures were NOK 3.2 billion, NOK 2.8 billion and NOK 2.2 billion in 2013, 2012 and 2011, 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.

8.1.8 Financial items

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Foreign exchange gains (losses) derivative financial instruments	(4.1)	2.1	1.6
Other foreign exchange gains (losses)	(4.5)	(1.3)	(2.2)
Net foreign exchange gains (losses)	(8.6)	0.8	(0.6)
Dividends received	0.1	0.1	0.1
Gains (losses) financial investments	1.9	0.6	(0.4)
Interest income financial investments	0.6	0.6	0.5
Interest income non-current financial receivables	0.1	0.1	0.1
Interest income current financial assets and other financial items	0.9	0.4	1.9
Interest income and other financial items	3.6	1.8	2.2
Interest expense bonds and bank loans and net interest on related derivatives	(1.5)	(2.5)	(2.2)
Interest expense finance lease liabilites	(0.2)	(0.5)	(0.6)
Capitalised borrowing costs	1.1	1.2	0.9
Accretion expense asset retirement obligations	(3.2)	(3.0)	(2.8)
Gains (losses) derivative financial instruments	(7.4)	3.0	6.9
Interest expense current financial liabilities and other finance expense	(0.8)	(0.7)	(1.8)
Interest and other finance expenses	(12.0)	(2.5)	0.4
Net financial items	(17.0)	0.1	2.0

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 5.4 billion, NOK 5.0 billion and NOK 4.7 billion from the financial liabilities at amortised cost category, partly offset by net interest on related derivatives from the held for trading category, NOK 3.9 billion, NOK 2.5 billion and NOK 2.5 billion for 2013, 2012 and 2011, respectively.

The line item Gains (losses) derivative financial instruments primarily includes fair value loss from the held for trading category of NOK 7.6 billion, gain of NOK 2.9 billion and gain of NOK 6.8 billion for 2013, 2012 and 2011, respectively.

In addition, net exchange loss of NOK 4.9 billion, gain of NOK 4.2 billion and gain of NOK 3.3 billion from the held for trading category is included in the line item Foreign exchange gains (losses) derivative financial instruments for 2013, 2012 and 2011, respectively.

An impairment loss of NOK 0.4 billion, NOK 2.1 billion and NOK 0.5 billion recognised for an investment classified in the available for sale category is included in Interest income current financial assets and other financial items in 2013, 2012 and 2011, respectively.

8.1.9 Income taxes

Significant components of income tax expense

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Current income tax expense in respect of current year	111.6	138.1	131.5
Prior period adjustments	1.3	(0.5)	0.2
Current income tax expense	112.9	137.6	131.7
Origination and reversal of temporary differences	(13.4)	0.3	7.0
Recognition of previously unrecognised deferred tax assets	0.0	(3.0)	(3.1)
Change in tax regulations	0.1	2.3	0.0
Prior period adjustments	(0.4)	0.0	(0.2)
Deferred tax expense	(13.7)	(0.4)	3.7
Income tax expense	99.2	137.2	135.4

Reconciliation of nominal statutory tax rate to effective tax rate

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Income before tax	138.4	206.7	213.8
Calculated income tax at statutory rate*	42.4	62.9	64.0
Calculated Norwegian Petroleum tax**	71.7	87.4	84.9
Tax effect of uplift**	(5.2)	(5.3)	(5.1)
Tax effect of permanent differences	(16.1)	(6.3)	(5.7)
Recognition of previously unrecognised deferred tax assets	0.0	(3.0)	(3.1)
Change in valuation allowance	3.9	0.3	(0.3)
Change in tax regulations	0.1	2.3	0.0
Prior period adjustments	0.9	(0.5)	0.0
Other items	1.5	(0.6)	0.7
Income tax expense	99.2	137.2	135.4
Effective tax rate	71.7 %	66.4 %	63.3 %

* The weighted average of statutory tax rates was 30.7% in 2013, 30.4% in 2012 and 29.9% in 2011. The increase from 2012 to 2013 was principally due to a change in the geographic mix of income, with a higher proportion of income in 2013 arising in jurisdictions subject to relatively higher tax rates. The increase from 2011 to 2012 was also due to such changes.

** When computing the petroleum tax of 50% (51% from 2014) on income from the Norwegian continental shelf, a tax-free allowance, or uplift, is granted at a rate of 7.5% per year for investments made prior to 5 May 2013. For investments made from 5 May 2013 the rate is 5.5% per year. Transitional rules apply to investments 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 is computed on the basis of the original capitalised cost of offshore production installations. 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 2013 and 2012, unrecognised uplift credits amounted to NOK 19.2 billion and NOK 17.5 billion, respectively.

Deferred tax assets and liabilities comprise

(in NOK billion)	Tax losses carried forward	Property, plant and equipment	Intangible assets	ARO	Pensions	Derivatives	Other	Total
Deferred tax at 31 December 2013								
Deferred tax assets	15.5	11.8	0.0	63.8	6.4	0.0	12.2	109.7
Deferred tax liabilities	0.0	(129.3)	(26.8)	0.0	0.0	(11.3)	(5.1)	(172.5)
Net asset (liability) at 31 December 2013	15.5	(117.5)	(26.8)	63.8	6.4	(11.3)	7.1	(62.8)
Deferred tax at 31 December 2012								
Deferred tax assets	10.7	7.7	0.0	63.4	5.6	0.0	9.6	97.0
Deferred tax liabilities	0.0	(127.5)	(20.9)	0.0	0.0	(18.1)	(7.8)	(174.3)
Net asset (liability) at 31 December 2012	10.7	(119.8)	(20.9)	63.4	5.6	(18.1)	1.8	(77.3)

Changes in net deferred tax liability during the year were as follows:

(in NOK billion)	2013	2012	2011
Net deferred tax liability at 1 January	77.3	76.8	76.2
Charged (credited) to the Consolidated statement of income	(13.7)	(0.4)	3.7
Other comprehensive income	(1.5)	1.7	(2.0)
Translation differences and other	0.7	(0.8)	(1.1)
Net deferred tax liability at 31 December	62.8	77.3	76.8

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)	2013	2012
Deferred tax assets	8.2	3.9
Deferred tax liabilities	71.0	81.2

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 2013 the deferred tax assets of NOK 8.2 billion are primarily recognised in Norway and Angola. At year end 2012 the deferred tax assets of NOK 3.9 billion were primarily recognised in the USA and Angola. In 2013 deferred tax assets in the USA are set-off against deferred tax liabilities.

Unrecognised deferred tax assets

	At 31 December	
(in NOK billion)	2013	2012
Deductible temporary differences	0.6	1.0
Tax losses carried forward	11.0	7.8

Approximately 27% of the unrecognised losses carry-forwards may be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2023. 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.

8.1.10 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.

		At 31 December	
(in millions)	2013	2012	2011
Weighted average number of ordinary shares	3,180.7	3,181.5	3,182.1
Weighted average number of ordinary shares, diluted	3,188.9	3,190.2	3,190.0

8.1.11 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 2012	18.4	816.4	56.6	7.4	99.0	997.8
Additions and transfers	1.6	77.0	3.0	0.8	36.7	119.0
Disposals at cost	(0.5)	(43.7)	(1.1)	(0.1)	(6.0)	(51.4)
Effect of changes in foreign exchange	1.6	20.3	1.6	0.4	5.8	29.7
Cost at 31 December 2013	21.1	869.9	60.2	8.4	135.5	1,095.1
Accumulated depreciation and impairment losses at 31 December 2012	(12.7)	(501.2)	(39.9)	(2.9)	(2.0)	(558.7)
Depreciation	(1.3)	(61.6)	(2.1)	(0.3)	0.0	(65.3)
Impairment losses	(0.9)	(1.1)	(2.7)	(0.5)	(2.0)	(7.2)
Reversal of impairment losses	0.0	0.0	0.0	0.0	0.2	0.2
Accumulated depreciation and impairment disposed assets	0.5	33.5	0.3	0.0	0.3	34.6
Effect of changes in foreign exchange	(1.1)	(9.7)	(0.5)	(0.1)	0.2	(11.3)
Accumulated depreciation and impairment losses at 31 December 2013	(15.5)	(540.1)	(44.9)	(3.8)	(3.3)	(607.7)
Carrying amount at 31 December 2013	5.6	329.8	15.2	4.6	132.2	487.4
Estimated useful lives (years)	3 - 20	*	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 2011	23.2	750.5	53.6	16.9	97.7	941.9
Additions and transfers	1.3	100.0	7.8	1.5	6.7	117.3
Disposals at cost	(4.8)	(19.1)	(3.8)	(10.7)	(1.5)	(39.9)
Effect of changes in foreign exchange	(1.3)	(15.0)	(1.0)	(0.3)	(3.9)	(21.5)
Cost at 31 December 2012	18.4	816.4	56.6	7.4	99.0	997.8
Accumulated depreciation and impairment losses at 31 December 2011	(15.5)	(469.1)	(40.7)	(7.2)	(1.8)	(534.3)
Depreciation	(1.4)	(55.1)	(1.9)	(0.5)	(0.2)	(59.1)
Impairment losses	0.0	(0.7)	(0.6)	0.0	0.0	(1.3)
Reversal of impairment losses	0.0	0.0	0.0	0.0	0.0	0.0
Accumulated depreciation and impairment disposed assets	3.4	16.7	2.8	4.7	0.0	27.6
Effect of changes in foreign exchange	0.8	7.0	0.5	0.1	0.0	8.4
Accumulated depreciation and impairment losses at 31 December 2012	(12.7)	(501.2)	(39.9)	(2.9)	(2.0)	(558.7)
Carrying amount at 31 December 2012	5.7	315.2	16.7	4.5	97.0	439.1
Estimated useful lives (years)	3 - 20	*	15 - 20	20 - 33		

* Depreciation according to unit of production method, see note 2 *Significant accounting policies*.

In 2013 a redetermination of the Ormen Lange Unit was concluded and as a result Statoil's ownership share was reduced by 3.57% to 25.35%. The effects of the redetermination on *Property, plant and equipment* are included on the Additions and transfers line.

The carrying amount of assets transferred to *Property, plant and equipment* from *Intangible assets* amounted to NOK 7.0 billion in both 2013 and 2012.

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 and estimated value in use. The base discount rate for value in use 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. 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. Also see note 3 *Segments* for further information on impairment losses recognised.

Statoil's unconventional activities in the US and Canada comprise cash generating units (CGUs) with a total carrying amount (*Property, plant and equipment* and *Intangible assets*) of approximately NOK 120 billion (including a goodwill amount of NOK 7 billion) which are sensitive to changes in oil and natural gas prices. A decrease in the long-term price assumptions would lead to the goodwill being impaired in full and also to a certain impairment of the individual CGUs' carrying values. For further description of how the group establishes recoverable amounts, reference is made to note 2 *Significant accounting policies*.

8.1.12 Intangible assets

(in NOK billion)	Exploration expenditures	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2012	18.6	57.3	9.7	2.7	88.3
Additions	6.3	2.0	0.0	0.3	8.7
Disposals at cost	(1.1)	(0.5)	0.0	0.0	(1.6)
Transfers	(2.9)	(4.0)	0.0	(0.1)	(7.0)
Expensed exploration expenditures previously capitalised	(1.9)	(1.2)	0.0	0.0	(3.1)
Effect of changes in foreign exchange	1.2	4.9	0.7	0.2	6.9
Cost at 31 December 2013	20.3	58.6	10.5	3.1	92.4
Accumulated amortisation and impairment losses at 31 December 2012			0.0	(0.7)	(0.7)
Amortisation and impairments for the year			0.0	(0.1)	(0.1)
Effect of changes in foreign exchange			0.0	(0.1)	(0.1)
Accumulated amortisation and impairment losses at 31 December 2013			0.0	(0.9)	(0.9)
Carrying amount at 31 December 2013	20.3	58.6	10.5	2.2	91.5

(in NOK billion)	Exploration expenditures	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2011	19.7	59.9	11.4	3.1	94.1
Additions	5.6	6.4	0.0	0.6	12.6
Disposals at cost	(0.5)	(0.1)	(1.2)	(0.8)	(2.6)
Transfers	(2.6)	(4.4)	0.1	(0.1)	(7.0)
Expensed exploration expenditures previously capitalised	(2.7)	(0.4)	0.0	0.0	(3.1)
Effect of changes in foreign exchange	(0.9)	(4.1)	(0.6)	(0.1)	(5.7)
Cost at 31 December 2012	18.6	57.3	9.7	2.7	88.3
Accumulated amortisation and impairment losses at 31 December 2011			(0.4)	(1.0)	(1.4)
Amortisation and impairments for the year			0.0	(0.1)	(0.1)
Amortisation and impairment losses disposed intangible assets			0.4	0.4	0.8
Accumulated amortisation and impairment losses at 31 December 2012			0.0	(0.7)	(0.7)
Carrying amount at 31 December 2012	18.6	57.3	9.7	2.0	87.6

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.

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 further information on the basis for impairment assessments.

The table below shows the aging of capitalised exploration expenditures.

(in NOK billion)	Amount capitalised
Less than one year	7.3
Between one and five years	11.6
Between five and nine years	1.4
Total	20.3

The table below shows the components of the exploration expenses.

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Exploration expenditures	21.8	20.9	18.8
Expensed exploration expenditures previously capitalised	3.1	3.1	1.5
Capitalised exploration	(6.9)	(5.9)	(6.5)
Exploration expenses	18.0	18.1	13.8

8.1.13 Financial investments and non-current prepayments

Non-current financial investments

(in NOK billion)	At 31 December 2013	2012
Bonds	10.0	8.9
Listed equity securities	5.6	4.9
Non-listed equity securities	0.9	1.2
Financial investments	16.4	15.0

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)	At 31 December 2013	2012
Financial receivables interest bearing	4.5	2.5
Prepayments and other non-interest bearing receivables	4.1	2.4
Prepayments and financial receivables	8.5	4.9

Financial receivables interest bearing primarily relate to loans to employees and project financing of subcontractors.

Current financial investments

	At 31 December	
(in NOK billion)	2013	2012
Bonds and time deposits	6.0	1.0
Treasury bills and commercial papers	33.2	13.9
Financial investments	39.2	14.9

At 31 December 2013 current *Financial investments* include NOK 5.3 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 2012 was NOK 5.4 billion.

For information about financial instruments by category, see note 25 *Financial instruments: fair value measurement and sensitivity analysis of market risk.*

8.1.14 Inventories

	At 31 December	
(in NOK billion)	2013	2012
Crude oil	15.2	13.7
Petroleum products	7.4	9.8
Other	7.0	1.8
Inventories	29.6	25.3

Other inventory consists mainly of spare parts and operational materials, including drilling and well equipment.

8.1.15 Trade and other receivables

	At 31 December	
(in NOK billion)	2013	2012
Trade receivables	64.9	55.3
Current financial receivables	2.4	1.0
Joint venture receivables	7.8	6.9
Associated companies and other related party receivables	0.4	0.5
Total financial trade and other receivables	75.6	63.7
Non-financial trade and other receivables	6.2	10.3
Trade and other receivables	81.8	74.0

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*.

8.1.16 Cash and cash equivalents

(in NOK billion)	At 31 December 2013	2012
Cash at bank available	8.5	7.3
Time deposits	37.1	21.4
Money market funds	6.1	2.8
Treasury bills and commercial papers	31.4	31.4
Restricted cash, including collateral deposits	2.3	2.3
Cash and cash equivalents	85.3	65.2

Restricted cash at 31 December 2013 and at 31 December 2012 includes collateral deposits of NOK 1.9 billion related to trading activities. 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.

8.1.17 Shareholders' equity

At 31 December 2013 and 2012, 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 6.75 in 2013, NOK 6.50 in 2012 and NOK 6.25 in 2011. A dividend of NOK 7.00 per share, amounting to a total dividend of NOK 22.3 billion, will be proposed at the annual general meeting in May 2014. The proposed dividend is not recognised as a liability in the Consolidated financial statements.

Total equity in the parent company Statoil ASA provides the basis for distribution of dividend to shareholders. As of 31 December 2013 total equity in Statoil ASA amounted to NOK 321.3 billion, of which NOK 112.2 billion is restricted equity. Total equity in the parent company as of 31 December 2012 was NOK 280.6 billion, of which NOK 105.5 billion was restricted equity. Restricted equity for 2013 is presented in accordance with the requirements in the Norwegian Limited Liabilities Companies Act effective 1 July 2013.

During 2013 a total of 3,937,641 treasury shares were purchased for NOK 0.5 billion. In 2012 a total of 3,278,561 treasury shares were purchased for NOK 0.5 billion. At 31 December 2013 Statoil had 9,734,733 treasury shares and at 31 December 2012 8,675,317 treasury shares, all of which are related to Statoil's share saving plan.

8.1.18 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). 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 7.1 billion and NOK 7.3 billion for 2013 and 2012, respectively), balances related to the SDFI (a decrease of NOK 1.3 billion and NOK 1.2 billion for 2013 and 2012, respectively) and project financing exposure that does not correlate to the underlying exposure (a decrease of NOK 0.2 billion and NOK 0.3 billion for 2013 and 2012, respectively). CE is defined as Statoil's total equity (including non-controlling interests) and ND.

(in NOK billion)	At 31 December 2013	2012
Net interest-bearing debt adjusted (ND)	63.7	45.1
Capital employed adjusted (CE)	419.7	365.0
Net debt to capital employed (ND/CE)	15.2 %	12.4 %

Non-current finance debt

Finance debt measured at amortised cost

	Weighted average interest rates in %		Carrying amount in NOK billion at 31 December		Fair value in NOK billion at 31 December	
	2013	2012	2013	2012	2013	2012
Unsecured bonds						
US dollar (USD)	3.76	4.52	117.4	69.9	118.4	80.2
Euro (EUR)	4.02	4.99	33.6	18.4	37.7	22.8
Great Britain pound (GBP)	6.08	6.71	13.8	9.2	17.7	13.8
Norwegian kroner (NOK)	4.18	-	3.0	-	3.1	-
Total			167.8	97.5	176.8	116.8
Unsecured loans						
US dollar (USD)	-	0.47	-	2.4	-	2.5
Japanese yen (JPY)	4.30	4.30	0.6	0.7	0.8	0.7
Euro (EUR)	3.35	-	1.3	-	1.3	-
Secured bank loans						
US dollar (USD)	4.52	4.33	0.2	0.4	0.2	0.4
Norwegian kroner (NOK)	3.20	3.57	0.2	0.1	0.2	0.1
Finance lease liabilities			5.0	5.6	5.0	5.6
Total			7.3	9.2	7.5	9.3
Total finance debt			175.0	106.7	184.3	126.1
Less current portion			9.6	5.7	9.6	5.9
Non-current finance debt			165.5	101.0	174.7	120.2

Unsecured bonds amounting to NOK 117.4 billion are denominated in USD and unsecured bonds amounting to NOK 37.9 billion are swapped into USD. Two bonds denominated in EUR and amounting to NOK 12.5 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*.

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.

The fair value of the non-current financial liabilities is determined using a discounted cash flow model. 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.

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.

Statoil's secured bank loans in USD have been secured by mortgage of shares in a subsidiary with a book value of NOK 1.8 billion, in addition, security includes Statoil's pro-rata share of income from a project. The secured bank loan in NOK has been secured by real estate and land with a total book value of NOK 0.4 billion.

In 2013 Statoil issued the following bonds:

Issuance date	Amount	Interest rate	Maturity date
15 May 2013	USD 0.75 billion	1.15%	May 2018
15 May 2013	USD 0.50 billion	floating	May 2018
15 May 2013	USD 0.90 billion	2.65%	January 2024
15 May 2013	USD 0.85 billion	3.95%	May 2043
27 August 2013	USD 0.30 billion	floating	August 2020
10 September 2013	EUR 0.85 billion	2.00%	September 2020
10 September 2013	EUR 0.65 billion	2.88%	September 2025
10 September 2013	GBP 0.35 billion	4.25%	April 2041
16 September 2013	NOK 2.00 billion	4.13%	September 2025
16 September 2013	NOK 1.00 billion	4.27%	September 2033
8 November 2013	USD 0.75 billion	1.95%	November 2018
8 November 2013	USD 0.75 billion	floating	November 2018
8 November 2013	USD 0.75 billion	2.90%	November 2020
8 November 2013	USD 1.00 billion	3.70%	March 2024
8 November 2013	USD 0.75 billion	4.80%	November 2043
12 December 2013	EUR 0.15 billion	3.35%	December 2033

Out of Statoil's total outstanding unsecured bond portfolio, 43 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 166.0 billion at the 31 December 2013 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)	At 31 December 2013	2012
Year 2 and 3	18.2	19.1
Year 4 and 5	30.1	10.8
After 5 years	117.1	71.1
Total repayment of non-current finance debt	165.5	101.0
Weighted average maturity (years)	10	9
Weighted average annual interest rate (%)	4.06	4.74

More information regarding finance lease liabilities is provided in note 22 *Leases*.

Current finance debt

(in NOK billion)	At 31 December 2013	2012
Collateral liabilities	7.4	12.4
Non-current finance debt due within one year	9.6	5.7
Other including bank overdraft	0.1	0.3
Total current finance debt	17.1	18.4
Weighted average interest rate (%)	2.12	1.02

Collateral liabilities relate to cash received as security for a portion of Statoil's credit exposure.

8.1.19 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.

The main pension schemes in Norway are managed by 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.

Statoil ASA and a number of its subsidiaries have defined benefit retirement plans, which cover substantially all of their employees.

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 new AFP scheme applicable from 1 January 2011. Statoil will pay a premium for both AFP schemes until 31 December 2015. After that date, premiums will only be due on the new AFP scheme. The premium in the new 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 new 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 AFP plan has been recognised as a defined benefit obligation.

Following the implementation of the amendment to IAS19 *Employee benefits*, the main change for Statoil is that expected return on plan assets should be set equal to the discount rate and is therefore no longer reflected in the pension assumptions. For more information, see note 2 *Significant accounting policies*.

The present values of the defined benefit obligation 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 2013 the discount rate for the defined benefit plans in Norway is established on the basis of seven years' mortgage covered bonds interest rate extrapolated on a 22.2 year 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 insignificant and are not disclosed separately.

Some Statoil companies have defined contribution plans. The period's contributions are recognised in the Consolidated statement of income as pension cost for the period.

Net pension cost

(in NOK billion)	For the year ended 31 December 2013	2012	2011
Current service cost	4.0	3.8	3.6
Interest cost	2.5	2.2	2.7
Interest (income) on plan asset	(2.1)	(2.5)	(2.9)
Losses (gains) from curtailment or settlement	0.0	(4.3)	0.0
Actuarial (gains) losses related to termination benefits	0.0	0.0	0.1
Defined benefit plans	4.4	(0.8)	3.5
Defined contribution plans	0.2	0.2	0.2
Multi-employer plans (previous AFP)	0.0	0.0	0.1
Total net pension cost	4.6	(0.6)	3.8

Pension cost includes associated social security tax and is partly charged to partners of Statoil operated licences.

In 2012 a curtailment gain of NOK 4.3 billion was recognised in the Consolidated statement of income following Statoil's decision to discontinue Statoil's supplementary (gratuity) part of the early retirement scheme for employees born after 1953, including NOK 0.5 billion related to Statoil Fuel and Retail ASA's redesign of its defined benefit plans.

(in NOK billion)	2013	2012
Defined benefit obligations (DBO)		
At 1 January	68.7	75.0
Current service cost	4.0	3.8
Interest cost	2.5	2.2
Actuarial (gains) losses - Demographic assumptions	5.8	0.0
Actuarial (gains) losses - Financial assumptions	4.8	(6.8)
Actuarial (gains) losses - Experience	(1.1)	3.4
Benefits paid	(2.0)	(1.8)
Losses (gains) from curtailment or settlement	0.0	(4.7)
Acquisition and sale	0.0	(2.4)
Foreign currency translation	0.1	0.0
At 31 December	82.8	68.7
Fair value of plan assets		
At 1 January	57.5	51.9
Interest Income	2.1	2.5
Return on plan assets (excluding interest income)	4.0	1.9
Company contributions (including social security tax)	3.1	4.2
Benefits paid	(1.1)	(0.7)
(Losses) gains from curtailment or settlement	0.0	(0.1)
Acquisition and sale	0.0	(2.2)
Foreign currency translation	0.2	0.0
At 31 December	65.8	57.5
Net benefit liability at 31 December	17.0	11.2
Represented by:		
Asset recognised as non-current pension assets (funded plan)	5.3	9.4
Liability recognised as non-current pension liabilities (unfunded plans)	22.3	20.6
DBO specified by funded and unfunded pension plans	82.8	68.7
Funded	60.6	48.1
Unfunded	22.3	20.6
Actual return on assets	6.1	4.4

The tables above for DBO and Fair value of plan assets do not include currency effects for Statoil ASA.

Actuarial losses and gains recognised directly in Other comprehensive income (OCI)

	For the year ended 31 December		
(in NOK billion)	2013	2012	2011
Net actuarial losses (gains) recognised during the year	5.5	(5.3)	7.4
Actuarial losses (gains) related to currency effects on net obligation and foreign exhange translation	0.4	(0.2)	0.0
Recognised directly in OCI during the year	(5.9)	5.5	(7.4)
Cumulative actuarial losses (gains) recognised directly in OCI net of tax	15.4	11.6	16.3

The net actuarial loss for 2013 is mainly related to an updated assessment of the demographic assumptions to be used for pension obligations in Norway.

In the table above, Actuarial losses (gains) related to currency effects on net obligation and foreign exchange translation include 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 %	
	For the year ended 31 December		For the year ended 31 December	
	2013	2012	2013	2012
Discount rate	3.75	3.25	4.00	3.75
Rate of compensation increase	3.25	3.00	3.50	3.25
Expected rate of pension increase	1.75	2.00	2.50	1.75
Expected increase of social security base amount (G-amount)	3.00	2.75	3.25	3.00
Weighted-average duration of the defined benefit obligation			22.2	21.9

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 2013 was 2.5%, 3.0%, 1.5%, 0.5% and 0.1% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively. Expected attrition at 31 December 2012 was 2.5%, 2.0%, 1.0%, 0.5% and 0.1% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

Due to increased life expectancy in the Norwegian population, new mortality tables (K2013) for collective pension funds have been issued by The Financial Supervisory Authority of Norway ("Finanstilsynet"). Statoil has assessed that applying the new mortality tables represents the best estimate when calculating pension liabilities for plans in Norway. Implementation of the new tables has resulted in a gross increase in defined benefit obligation in 2013 of NOK 7.4 billion. Previously, the mortality table K2005 including the minimum requirements from The Financial Supervisory Authority of Norway ("Finanstilsynet") was used.

For 2013 Statoil has implemented new disability tables for plans in Norway. Analyses done in 2013 indicates that actual disabilities for Statoil in Norway are lower than the expectations reflected in the previous table. The new disability tables have been developed by the actuary and represents the best etimate when calculating pension liabilities for plans in Norway. The implementation of these disability tables resulted in a decrease in defined benefit obligation of NOK 1.6 billion. The previous disability table, KU, was developed by the insurance company Storebrand.

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 2013. Actual results may materially deviate from these estimates.

	Discount rate		Rate of compensation increase		Social security base amount		Expected rate of pension increase	
(in NOK billion)	0.50 %	-0.50 %	0.50 %	-0.50 %	0.50 %	-0.50 %	0.50 %	-0.50 %
Changes in:								
Defined benefit obligation at 31 December 2013	(7.7)	8.6	4.0	(4.0)	(0.7)	0.8	4.8	(4.8)
Service cost 2014	(0.6)	0.7	0.4	(0.4)	(0.1)	0.1	0.3	(0.3)

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 at 31 December 2013 and 2012. Statoil Pension invests in both financial assets and real estate.

Real estate properties owned by Statoil Pension amounted to NOK 3.1 billion and NOK 2.1 billion of total pension assets at 31 December 2013 and 2012, respectively, and are rented to Statoil companies.

The table below presents the portfolio weighting as approved by the board of the Statoil Pension for 2013. The portfolio weight during a year will depend on the risk capacity.

	Pension assets on investments classes		Portfolio weight*	
(in %)	2013	2012		
Equity securities	39.6	38.8	40.0	(+/-5)
Bonds	37.6	41.5	45.0	(+/-5)
Money market instruments	17.2	15.0	15.0	(+/-15)
Real estate	5.1	3.9		
Other assets	0.5	0.8		
Total	100.0	100.0	100.0	

* The interval in brackets expresses the scope of tactical deviation by Statoil Kapitalforvaltning ASA (the asset manager).

In 2013 100% of the equity securities, 84% of bonds and 96% of money marked instruments had quoted market prices in an active market (Level 1). In 2012 100% of the equity securities, 34% of bonds and 90% of money marked 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 2014.

8.1.20 Provisions

(in NOK billion)	Asset retirement obligations	Other provisions	Total
Non-current portion at 31 December 2012	89.0	6.5	95.5
Current portion at 31 December 2012 reported as trade and other payables	1.3	7.1	8.4
Provisions at 31 December 2012	90.3	13.6	103.9
New or increased provisions	19.8	12.1	32.0
Unused amounts reversed	(1.2)	0.0	(1.1)
Amounts charged against provisions	(1.2)	(0.9)	(2.0)
Effects of change in the discount rate	(16.2)	(0.1)	(16.3)
Reduction due to divestments	(5.0)	(0.3)	(5.3)
Accretion expenses	3.2	0.0	3.2
Reclassification and transfer	0.0	(0.1)	(0.1)
Currency translation	1.7	1.3	3.0
Provisions at 31 December 2013	91.6	25.6	117.2
Current portion at 31 December 2013 reported as trade and other payables	2.1	13.3	15.4
Non-current portion at 31 December 2013	89.5	12.3	101.7

Expected timing of cash outflows

(in NOK billion)	Asset retirement obligations	Other provisions	Total
2014 - 2018	10.2	21.2	31.4
2019 - 2023	9.3	0.2	9.5
2024 - 2028	19.6	0.1	19.7
2029 - 2033	20.4	0.2	20.6
Thereafter	32.1	3.9	36.0
At 31 December 2013	91.6	25.6	117.2

The increase in the asset retirement obligations is mainly due to increase in the expected plugging and abandonment expense, additional wells drilled during the year, increased inflation and change in expected removal year.

The timing of cash outflows related to asset retirement obligations primarily depend on when the production ceases at the various facilities.

In the first quarter of 2013 Statoil entered into an agreement for early termination of certain US-based terminal capacity contracts. In combination with the fact that the unfavourable development in the US gas market and Statoil's expectation of no future utilisation of certain US-based terminal capacity contracts for the remaining contract term have been sustained over a period of time, this led to the recognition of an onerous contract provision of NOK 4.9 billion within *Net operating income* in the Consolidated statement of income. NOK 4.1 billion of the provisions were recognised within the Marketing, Processing and Renewable Energy (MPR) segment and NOK 0.8 billion within the Development and Production Norway (DPN) segment. At 31 December 2013, the non-current portion of NOK 3.0 billion has been reflected within *Provisions* in the Consolidated balance sheet, and the current portion of NOK 1.3 billion has been reflected in *Trade and other payables*. No tax asset was recognised for the MPR related provisions. As a result of the recognition of the onerous contract provisions, all the US-based terminal capacity related contract commitments previously included in Statoil's year end disclosure of long-term commitments are now provided for in the Consolidated balance sheet.

The other provisions category mainly relates to expected payments on unresolved claims. The timing and amounts of potential settlements in respect of these provisions are uncertain and dependent on various factors that are outside management's control.

See also comments on provisions in note 23 *Other commitments and contingencies*.

For further information of methods applied and estimates required, see note 2 *Significant accounting policies*.

8.1.21 Trade and other payables

(in NOK billion)	At 31 December 2013	2012
Trade payables	28.3	25.9
Non-trade payables and accrued expenses	19.0	17.1
Joint venture payables	22.4	19.8
Associated companies and other related party payables	9.5	9.4
Total financial trade and other payables	79.2	72.2
Current portion of provisions and other payables	16.4	9.6
Trade and other payables	95.6	81.8

Included in Current portion of provisions and other payables are certain provisions that are further described in note 20 *Provisions* and note 23 *Other commitments and contingencies*. 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 associated companies and other related parties, see note 24 *Related parties*.

8.1.22 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

In 2013, net rental expenses were NOK 17.4 billion (NOK 17.6 billion in 2012 and NOK 13.7 billion in 2011) of which minimum lease payments were NOK 21.2 billion (NOK 20.0 billion in 2012 and NOK 16.0 billion in 2011) and sublease payments received were NOK 3.8 billion (NOK 2.4 billion in both 2012 and 2011). No material contingent rent payments have been expensed in 2013, 2012 or 2011.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2013.

	Operating leases					
(in NOK billion)	Rigs	Vessels	Other	Total	Sublease	Net total
2014	21.0	4.0	1.4	26.4	(3.7)	22.7
2015	18.1	3.0	1.6	22.7	(2.0)	20.7
2016	12.8	2.5	1.3	16.6	(1.7)	14.8
2017	6.4	1.9	1.3	9.6	(0.8)	8.8
2018	4.9	1.7	1.1	7.8	(0.7)	7.1
Thereafter	13.9	5.2	9.9	29.0	(2.3)	26.7
Total future minimum lease payments	77.2	18.2	16.6	112.1	(11.3)	100.8

Statoil had certain operating lease contracts for drilling rigs at 31 December 2013. The remaining significant contracts' terms range from three months 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 licences 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 2013 included four crude tankers. The contract's estimated nominal amount was approximately NOK 4.6 billion at year end 2013, and it is included in Vessels in the table above.

The category Other operating leases includes future minimum lease payments of NOK 4.6 billion related to the lease of two office buildings located in Bergen and owned by Statoil Pension, one of which is currently under construction. These operating lease commitments to a related party extend to the year 2034. NOK 3.6 billion of the total is payable after 2018.

Statoil had finance lease liabilities of NOK 5.0 billion at 31 December 2013. The nominal minimum lease payments related to these finance leases amount to NOK 7.3 billion. *Property, plant and equipment* includes NOK 4.9 billion for finance leases that have been capitalised at year end (NOK 4.4 billion in 2012), also presented mainly within the category Machinery, equipment and transportation equipment including vessels in note 11 *Property, plant and equipment*.

8.1.23 Other commitments and contingencies

Contractual commitments
Statoil had contractual commitments of NOK 70.2 billion at 31 December 2013. 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 2013, Statoil was committed to participate in 61 wells, with an average ownership interest of approximately 38%. Statoil's share of estimated expenditures to drill these wells amounts to NOK 13.7 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 tables 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 using the equity method are included gross in the tables below. For assets (for example pipelines) that Statoil accounts for by recognising its share of assets, liabilities, income and expenses (capacity costs) on a line-by-line basis in the Consolidated financial statements, the amounts in the table include the net commitment payable by Statoil (i.e. gross commitment less the non-Statoil share).

Nominal minimum other long-term commitments at 31 December 2013:

(in NOK billion)	
2014	12.6
2015	12.4
2016	11.8
2017	12.3
2018	11.9
Thereafter	170.6
Total	231.6

In connection with the final investment decision in December 2013 for the stage 2 development of the Shah Deniz gas field in Azerbaijan, the BP-operated consortium has entered into long-term agreements for pipeline transportation. Statoil's 25.5% share of the nominal minimum commitments as of 31 December 2013 was NOK 81.1 billion (USD 13.3 billion). The sale of Statoil's ownership interests in Shah Deniz, reducing the ownership share from 25.5% to 15.5% announced in December 2013, will reduce the commitment by NOK 31.8 billion (USD 5.2 billion).

Contingencies
A number of Statoil's 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 6.9 billion for gas delivered prior to year end 2013. 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 reduction.

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 2010. 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 2013, the exposure for Statoil at year end 2013 is estimated at USD 0.9 billion (NOK 5.5 billion), the most significant part of which relates to profit oil elements. Statoil has provided in the 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.

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 claims that in aggregate from the year 2009 to 2013, Contractor has lifted excess volumes compared to the PSC terms, and consequently NNPC has increased its lifting of oil. The Contractor disputes NNPC's position. Arbitration has been initiated in the matter in accordance with the terms of the PSC. NNPC and the Nigerian Federal Inland Revenue Service are contesting the legality of the arbitration process as far as resolving tax related disputes goes, and are actively pursuing this view through the channels of the Nigerian legal system. The exposure for Statoil at year end 2013 is mainly related to cost oil and profit oil volumes and has been estimated at USD 0.3 billion (NOK 1.7 billion). Statoil has provided in the Consolidated financial statements for its best estimate related to the claims, which has been reflected in the Consolidated statement of income as a reduction of revenue.

Through its ownership in OML 128 in Nigeria, Statoil is party to an ownership interest redetermination process for the Agbami field for which the outcome is uncertain. Statoil has disputed certain aspects of the basis for the redetermination, and an arbitration process has been initiated in the fourth quarter of 2013. The exposure for Statoil at year end 2013 has been estimated to approximately USD 0.7 billion (NOK 4.3 billion). Statoil has made provisions based on its best estimate for the redetermination process. The provision has been reflected within *Provisions* in the Consolidated balance sheet at year end 2013.

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 and disputes are reflected within note 20 *Provisions*.

8.1.24 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 2013 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet (Norwegian national insurance fund) of 3.4%). 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 92.5 billion, NOK 96.6 billion and NOK 95.5 billion in 2013, 2012 and 2011, respectively. Purchases of natural gas regarding the Tjelbergodden methanol plant from the Norwegian State amounted to NOK 0.5 billion in 2013 and NOK 0.4 billion in both 2012 and 2011. The most significant items included in the line item Associated companies 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 such as pipeline transport, gas storage and processing of petroleum products, Statoil also has regular transactions with certain entities 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.

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 2013 is presented in note 5 *Remuneration* in the financial statements of the parent company, Statoil ASA.

8.1.25 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 2013							
Assets							
Non-current derivative financial instruments		0.0	0.0	22.1	0.0	0.0	22.1
Non-current financial investments	13	0.0	0.9	0.0	15.6	0.0	16.4
Prepayments and financial receivables	13	4.5	0.0	0.0	0.0	4.1	8.5
Trade and other receivables	15	75.5	0.0	0.0	0.0	6.2	81.8
Current derivative financial instruments		0.0	0.0	2.9	0.0	0.0	2.9
Current financial investments	13	0.0	0.0	33.9	5.3	0.0	39.2
Cash and cash equivalents	16	47.9	0.0	37.4	0.0	0.0	85.3
Total		127.9	0.9	96.3	20.9	10.3	256.2

				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 2012							
Assets							
Non-current derivative financial instruments		0.0	0.0	33.2	0.0	0.0	33.2
Non-current financial investments	13	0.0	1.2	0.0	13.8	0.0	15.0
Prepayments and financial receivables	13	2.5	0.0	0.0	0.0	2.4	4.9
Trade and other receivables	15	63.7	0.0	0.0	0.0	10.3	74.0
Current derivative financial instruments		0.0	0.0	3.6	0.0	0.0	3.6
Current financial investments	13	0.0	0.0	9.5	5.4	0.0	14.9
Cash and cash equivalents	16	31.0	0.0	34.2	0.0	0.0	65.2
Total		97.2	1.2	80.5	19.2	12.7	210.8

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2013					
Liabilities					
Non-current finance debt	18	165.5	0.0	0.0	165.5
Non-current derivative financial instruments		0.0	2.2	0.0	2.2
Trade and other payables	21	79.2	0.0	16.4	95.6
Current finance debt	18	17.1	0.0	0.0	17.1
Current derivative financial instruments		0.0	1.5	0.0	1.5
Total		261.8	3.7	16.4	281.9

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2012					
Liabilities					
Non-current finance debt	18	101.0	0.0	0.0	101.0
Non-current derivative financial instruments		0.0	2.7	0.0	2.7
Trade and other payables	21	72.2	0.0	9.6	81.8
Current finance debt	18	18.4	0.0	0.0	18.4
Current derivative financial instruments		0.0	1.1	0.0	1.1
Total		191.6	3.8	9.6	205.0

Fair value hierarchy

The following table summarises each class of financial instruments which are recognised in the 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 2013								
Level 1	14.2	0.0	4.9	0.0	0.0	0.0	0.0	19.1
Level 2	1.4	10.1	34.3	1.6	37.4	(2.2)	(1.5)	81.1
Level 3	0.9	12.0	0.0	1.3	0.0	0.0	0.0	14.2
Total fair value	16.4	22.1	39.2	2.9	37.4	(2.2)	(1.5)	114.4
At 31 December 2012								
Level 1	8.1	0.0	4.7	0.0	0.0	0.0	0.0	12.8
Level 2	5.7	16.6	10.2	2.2	34.2	(2.7)	(1.1)	65.1
Level 3	1.2	16.6	0.0	1.4	0.0	0.0	0.0	19.2
Total fair value	15.0	33.2	14.9	3.6	34.2	(2.7)	(1.1)	97.1

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 and Non-current derivative financial instruments - assets in the above table. 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. Had Statoil applied this assumption, the fair value of the contracts included would have decreased by approximately NOK 0.5 billion at end of 2013 and decreased by NOK 1.6 billion at end of 2012 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2013 and 2012 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	Total amount
For the year ended 31 December 2013				
Opening balance	1.2	16.6	1.4	19.2
Total gains and losses recognised				
- in statement of income	(0.4)	(5.4)	1.3	(4.5)
- in other comprehensive income	0.0	0.0	0.0	0.0
Purchases	0.3	0.0	0.0	0.3
Sales	0.0	0.7	0.0	0.7
Settlement	(0.3)	0.0	(1.4)	(1.7)
Foreign currency translation differences	0.1	0.0	0.0	0.1
Closing balance	0.9	12.0	1.3	14.2
For the year ended 31 December 2012				
Opening balance	2.7	17.7	1.5	21.9
Total gains and losses recognised				
- in statement of income	(2.0)	(1.2)	1.4	(1.8)
- in other comprehensive income	0.0	0.0	0.0	0.0
Purchases	0.5	0.1	0.0	0.6
Settlement	0.0	0.0	(1.5)	(1.5)
Transfer into level 3	0.2	0.0	0.0	0.2
Foreign currency translation differences	(0.2)	0.0	0.0	(0.2)
Closing balance	1.2	16.6	1.4	19.2

The assets within Level 3 during 2013 have had a net decrease in the fair value of NOK 5.0 billion. Of the NOK 4.5 billion recognised in the Consolidated statement of income during 2013, NOK 4.1 billion is related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements, NOK 1.4 billion included in the opening balance for 2013 has been fully realised as the underlying volumes have been delivered during 2013 and the amount is presented as settled in the above table.

Substantially all gains and losses recognised in the Consolidated statement of income during 2013 are related to assets held at the end of 2013.

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 are mainly related to non-exchange traded derivative 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 2013 and 2012 have been calculated assuming a reasonably possible change of 40% in crude oil, refined products, electricity and natural gas prices.

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)	-40% sensitivity	40% sensitivity
At 31 December 2013		
Crude oil and refined products net gains (losses)	(6.6)	6.6
Natural gas and electricity net gains (losses)	(0.2)	0.2
At 31 December 2012		
Crude oil and refined products net gains (losses)	(7.9)	7.9
Natural gas and electricity net gains (losses)	1.1	(1.0)

Currency risk
Currency risks constitute significant financial risks 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 risks and how Statoil manages these risks, see note 5 *Financial risk management*.

The following currency risk sensitivities at the end of 2013 and 2012 have been calculated by assuming a 9% reasonably possible change in the main foreign exchange rates that Statoil is exposed to. An increase in the foreign exchange rates by 9% 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)	- 9% sensitivity	9% sensitivity
At 31 December 2013		
USD net gains (losses)	8.7	(8.7)
NOK net gains (losses)	(8.0)	8.0
At 31 December 2012		
USD net gains (losses)	8.4	(8.4)
NOK net gains (losses)	(7.7)	7.7

Interest rate risk
Interest rate risks constitute significant financial risks 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 1.0 percentage point reasonably possible changes in the interest rates at the end of 2013. At the end of 2012 a change of 0.7 percentage points in the interest rates were 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)	Gains	Losses
At 31 December 2013		
Interest rate risk (1.0 percentage point sensitivity)	6.1	(6.1)
At 31 December 2012		
Interest rate risk (0.7 percentage point sensitivity)	4.2	(4.2)

8.1.26 Condensed consolidating 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 consolidating 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 consolidating information presented below reflects the transfer of Norwegian continental shelf assets to Statoil Petroleum AS for all periods presented. The condensed consolidating 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 consolidating financial information as of 31 December 2013 and 2012, and for the years ended 31 December 2013, 2012 and 2011.

CONDENSED CONSOLIDATING STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

For the year ended 31 December 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	214.9	(223.2)	637.2
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	214.7	(269.8)	637.4
Total operating expenses	(418.3)	(85.5)	(201.8)	223.6	(481.9)
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 CONSOLIDATING STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

For the year ended 31 December 2012 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	480.2	251.8	260.8	(272.5)	720.3
Net income from equity accounted companies	58.5	(1.3)	0.7	(56.2)	1.7
Total revenues and other income	538.7	250.5	261.5	(328.7)	722.0
Total operating expenses	(480.4)	(76.8)	(229.1)	270.9	(515.4)
Net operating income	58.3	173.7	32.4	(57.8)	206.6
Net financial items	18.8	(5.1)	(8.8)	(4.8)	0.1
Income before tax	77.1	168.6	23.6	(62.6)	206.7
Income tax	(5.1)	(123.7)	(8.7)	0.3	(137.2)
Net income	72.0	44.9	14.9	(62.3)	69.5
Other comprehensive income	(12.9)	(6.7)	(11.7)	23.4	(7.9)
Total comprehensive income	59.1	38.2	3.2	(38.9)	61.6

CONDENSED CONSOLIDATING STATEMENT OF INCOME AND OTHER COMPREHENSIVE INCOME

For the year ended 31 December 2011 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	462.7	257.5	225.0	(276.5)	668.7
Net income from equity accounted companies	70.5	11.1	4.4	(84.7)	1.3
Total revenues and other income	533.2	268.6	229.4	(361.2)	670.0
Total operating expenses	(463.3)	(79.4)	(192.8)	277.3	(458.2)
Net operating income	69.9	189.2	36.6	(83.9)	211.8
Net financial items	9.1	(3.9)	(4.8)	1.6	2.0
Income before tax	79.0	185.3	31.8	(82.3)	213.8
Income tax	(1.8)	(125.8)	(7.8)	0.0	(135.4)
Net income	77.2	59.5	24.0	(82.3)	78.4
Other comprehensive income	2.2	1.8	3.3	(6.8)	0.5
Total comprehensive income	79.4	61.3	27.3	(89.1)	78.9

CONDENSED CONSOLIDATING BALANCE SHEET

At 31 December 2013 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.4	259.5	313.6	0.4	578.9
Equity accounted companies	401.7	138.9	6.6	(539.9)	7.4
Other non-current assets	26.5	13.3	20.7	0.0	60.5
Non-current financial receivables from subsidiaries	69.4	0.6	0.2	(70.1)	0.0
Total non-current assets	503.1	412.3	341.0	(609.6)	646.8
Current receivables from subsidiaries	15.2	41.9	63.2	(120.2)	0.0
Other current assets	100.5	14.9	43.8	(5.7)	153.5
Cash and cash equivalents	77.0	0.0	8.3	0.0	85.3
Total current assets	192.7	56.7	115.3	(125.9)	238.8
Total assets	695.8	469.1	456.3	(735.5)	885.6
EQUITY AND LIABILITIES					
Total equity	355.5	184.4	359.9	(543.8)	356.0
Non-current liabilities to subsidiaries	0.1	67.0	3.0	(70.1)	0.0
Other non-current liabilities	190.4	138.4	34.8	(1.0)	362.7
Total non-current liabilities	190.5	205.5	37.8	(71.1)	362.7
Other current liabilities	57.8	68.1	41.4	(0.4)	166.9
Current liabilities to subsidiaries	91.9	11.0	17.3	(120.2)	0.0
Total current liabilities	149.7	79.1	58.6	(120.6)	166.9
Total liabilities	340.3	284.6	96.5	(191.7)	529.6
Total equity and liabilities	695.8	469.1	456.3	(735.5)	885.6

CONDENSED CONSOLIDATING BALANCE SHEET

At 31 December 2012 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
ASSETS					
Property, plant, equipment and intangible assets	5.3	247.0	274.4	0.0	526.7
Equity accounted companies	368.4	147.7	5.9	(513.7)	8.3
Other non-current assets	30.5	18.7	17.2	0.0	66.4
Non-current financial receivables from subsidiaries	69.1	0.4	0.2	(69.7)	0.0
Total non-current assets	473.3	413.8	297.7	(583.4)	601.4
Current receivables from subsidiaries	12.2	26.1	117.6	(155.9)	0.0
Other current assets	69.1	12.3	42.4	(6.0)	117.8
Cash and cash equivalents	57.4	0.0	7.8	0.0	65.2
Total current assets	138.7	38.4	167.8	(161.9)	183.0
Total assets	612.0	452.2	465.5	(745.3)	784.4
EQUITY AND LIABILITIES					
Total equity	319.2	124.3	394.3	(517.9)	319.9
Non-current liabilities to subsidiaries	0.1	67.7	1.9	(69.7)	0.0
Other non-current liabilities	128.4	146.9	27.3	(1.6)	301.0
Total non-current liabilities	128.5	214.6	29.2	(71.3)	301.0
Other current liabilities	52.0	74.2	37.5	(0.2)	163.5
Current liabilities to subsidiaries	112.3	39.1	4.5	(155.9)	0.0
Total current liabilities	164.3	113.3	42.0	(156.1)	163.5
Total liabilities	292.8	327.9	71.2	(227.4)	464.5
Total equity and liabilities	612.0	452.2	465.5	(745.3)	784.4

CONDENSED CONSOLIDATING CASH FLOW STATEMENT

For the year ended 31 December 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 year (net of overdraft)	57.4	0.0	7.5	0.0	64.9
Cash and cash equivalents at the end of the year (net of overdraft)	77.0	0.0	8.3	0.0	85.3

For the year ended 31 December 2012 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	78.1	94.0	40.9	(85.0)	128.0
Cash flows provided by (used in) investing activities	(62.9)	(76.9)	(79.0)	122.2	(96.6)
Cash flows provided by (used in) financing activities	0.9	(17.1)	35.2	(37.2)	(18.2)
Net increase (decrease) in cash and cash equivalents	16.1	0.0	(2.9)	0.0	13.2
Effect of exchange rate changes on cash and cash equivalents	(1.4)	0.0	(0.5)	0.0	(1.9)
Cash and cash equivalents at the beginning of the year (net of overdraft)	42.7	0.0	10.9	0.0	53.6
Cash and cash equivalents at the end of the year (net of overdraft)	57.4	0.0	7.5	0.0	64.9

For the year ended 31 December 2011 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Cash flows provided by (used in) operating activities	37.4	81.5	30.3	(30.2)	119.0
Cash flows provided by (used in) investing activities	18.7	(61.9)	(46.7)	5.0	(84.9)
Cash flows provided by (used in) financing activities	(35.9)	(19.6)	17.6	25.2	(12.7)
Net increase (decrease) in cash and cash equivalents	20.2	0.0	1.2	0.0	21.4
Effect of exchange rate changes on cash and cash equivalents	1.2	0.0	(1.4)	0.0	(0.2)
Cash and cash equivalents at the beginning of the year (net of overdraft)	21.3	0.0	11.1	0.0	32.4
Cash and cash equivalents at the end of the year (net of overdraft)	42.7	0.0	10.9	0.0	53.6

8.1.27 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 2013 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

The known effects of the agreement to divest 10% of Statoil's 25.5% holdings in the Shah Deniz field in Azerbaijan, the agreement with PTTEP to divide the interests in the KKD oil sand project in Canada and the reduced equity share in the Snorre field in Norway will all be included in 2014. The net effect of these changes will be a reduction in proved reserves at year end 2014 of approximately 125 million boe.

The subtotals and totals in some of the tables may not equal the sum of the amounts shown due to rounding.

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 2013, 14% of total proved reserves were related to such agreements (18% of oil and natural gas liquids (NGL) and 11% of gas). This compares with 9% and 10% of total proved reserves for 2012 and 2011, respectively. Net entitlement oil and gas production from fields with such agreements was 93 million boe during 2013 (89 million boe for 2012 and 75 million boe for 2011). 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. Oil reserves at year-end 2013 have been determined based on a 12-month average 2013 Brent blend price equivalent to USD 108.02/bbl. The slight decrease in oil price from 2012, when the average Brent blend price was USD 111.13/bbl, has had no material effect on the profitable oil to be recovered from the accumulations, or on Statoil's proved oil reserves under PSAs and similar contracts. Gas reserves at year end 2013 have been determined based on achieved gas prices during 2013 giving a volume weighted average gas price of 2.13 NOK/Sm3. The comparable volume weighted average gas price used to determine gas reserves at year end 2012 was 2.3 NOK/Sm3. Gas prices in other parts of the world increased slightly from 2012, resulting in minor reduction in gas reserves. These changes are all included in the revision category in the tables below.

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 fulfill 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 70% of total proved reserves at 31 December 2013 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 to include 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 2010 through 2013, and the changes therein.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and NGL reserves in million barrels oil equivalent							
At 31 December 2010	1,241	170	313	299	2,023	101	2,124
Revisions and improved recovery	295	(42)	46	11	310	(1)	309
Extensions and discoveries	71	-	-	60	132	-	132
Purchase of reserves-in-place	14	-	-	106	120	-	120
Sales of reserves-in-place	-	-	-	(66)	(66)	-	(66)
Production	(252)	(15)	(46)	(26)	(338)	(5)	(343)
At 31 December 2011	1,369	114	313	385	2,181	95	2,276
Revisions and improved recovery	150	12	42	21	225	(8)	217
Extensions and discoveries	100	85	-	81	266	-	266
Purchase of reserves-in-place	-	-	-	1	1	-	1
Sales of reserves-in-place	(17)	-	-	(1)	(17)	-	(17)
Production	(231)	(17)	(56)	(46)	(349)	(5)	(353)
At 31 December 2012	1,372	193	299	441	2,306	82	2,389
Revisions and improved recovery	158	16	40	22	235	(16)	219
Extensions and discoveries	19	47	8	44	119	-	119
Purchase of reserves-in-place	13	-	-	-	13	-	13
Sales of reserves-in-place	(61)	(15)	-	(2)	(77)	-	(77)
Production	(216)	(15)	(59)	(50)	(341)	(4)	(345)
At 31 December 2013	1,286	227	288	455	2,255	63	2,318

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 gas reserves in billion standard cubic feet							
At 31 December 2010	16,343	634	521	466	17,965	-	17,965
Revisions and improved recovery	383	22	(50)	4	359	-	359
Extensions and discoveries	111	-	-	451	563	-	563
Purchase of reserves-in-place	138	-	-	90	227	-	227
Sales of reserves-in-place	-	-	-	-	-	-	-
Production	(1,287)	(48)	(40)	(59)	(1,434)	-	(1,434)
At 31 December 2011	15,689	608	431	952	17,681	-	17,681
Revisions and improved recovery	824	29	(49)	(39)	766	-	766
Extensions and discoveries	279	-	-	352	630	-	630
Purchase of reserves-in-place	-	-	-	18	18	-	18
Sales of reserves-in-place	(305)	-	-	(14)	(319)	-	(319)
Production	(1,483)	(62)	(41)	(161)	(1,748)	-	(1,748)
At 31 December 2012	15,003	575	341	1,107	17,027	-	17,027
Revisions and improved recovery	391	187	27	382	987	-	987
Extensions and discoveries	920	1,236	-	112	2,268	-	2,268
Purchase of reserves-in-place	5	-	-	-	5	-	5
Sales of reserves-in-place	(295)	(3)	-	(2)	(300)	-	(300)
Production	(1,264)	(72)	(40)	(196)	(1,571)	-	(1,571)
At 31 December 2013	14,761	1,923	328	1,404	18,416	-	18,416

The effect of the reduced equity share in Shah Deniz is not included in the table above, but will be included in 2014 after the closing date of the transaction.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil, NGL and gas reserves in million barrels oil equivalent							
At 31 December 2010	4,153	283	406	382	5,224	101	5,325
Revisions and improved recovery	364	(38)	37	12	374	(1)	373
Extensions and discoveries	91	-	-	141	232	-	232
Purchase of reserves-in-place	38	-	-	122	161	-	161
Sales of reserves-in-place	-	-	-	(66)	(66)	-	(66)
Production	(481)	(23)	(53)	(36)	(593)	(5)	(598)
At 31 December 2011	4,165	222	390	555	5,331	95	5,426
Revisions and improved recovery	297	17	33	14	361	(8)	353
Extensions and discoveries	150	85	-	144	378	-	378
Purchase of reserves-in-place	-	-	-	4	4	-	4
Sales of reserves-in-place	(71)	-	-	(4)	(74)	-	(74)
Production	(495)	(28)	(63)	(74)	(660)	(5)	(665)
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	-	523
Purchase of reserves-in-place	14	-	-	-	14	-	14
Sales of reserves-in-place	(113)	(15)	-	(2)	(131)	-	(131)
Production	(441)	(28)	(66)	(85)	(621)	(4)	(625)
At 31 December 2013	3,916	569	346	705	5,537	63	5,600

Proved reserves of bitumen in Americas, representing less than 2% of Statoil's proved reserves, is included as oil in the table above. The effect of the reduced equity share in Shah Deniz is not included in the table above, but will be included in 2014 after the closing date of the transaction.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and NGL reserves in million barrels oil equivalent							
At 31 December 2010							
Developed	950	99	192	82	1,322	35	1,356
Undeveloped	291	71	121	218	701	66	767
At 31 December 2011							
Developed	919	102	219	103	1,344	37	1,381
Undeveloped	450	11	93	282	837	58	895
At 31 December 2012							
Developed	842	79	232	191	1,344	38	1,383
Undeveloped	530	114	67	250	962	44	1,006
At 31 December 2013							
Developed	834	63	206	246	1,350	32	1,382
Undeveloped	451	164	81	209	906	30	936
Net proved gas reserves in billion standard cubic feet							
At 31 December 2010							
Developed	13,721	421	221	336	14,698	-	14,698
Undeveloped	2,622	214	300	130	3,267	-	3,267
At 31 December 2011							
Developed	12,661	371	293	404	13,730	-	13,730
Undeveloped	3,027	237	138	548	3,951	-	3,951
At 31 December 2012							
Developed	12,073	343	226	567	13,210	-	13,210
Undeveloped	2,931	232	115	540	3,817	-	3,817
At 31 December 2013							
Developed	11,580	467	209	817	13,073	-	13,073
Undeveloped	3,181	1,455	120	586	5,343	-	5,343
Net proved oil, NGL and gas reserves in million barrels oil equivalent							
At 31 December 2010							
Developed	3,394	174	231	142	3,941	35	3,975
Undeveloped	758	109	175	241	1,283	66	1,350
At 31 December 2011							
Developed	3,175	168	272	175	3,790	37	3,827
Undeveloped	990	54	118	380	1,541	58	1,599
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

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 production activities

Consolidated companies

(in NOK billion)	2013	At 31 December 2012	2011
Unproved properties	83.8	76.0	79.9
Proved properties, wells, plants and other equipment	984.1	896.7	827.5
Total capitalised cost	1,067.9	972.7	907.4
Accumulated depreciation, impairment and amortisation	(543.7)	(498.2)	(466.3)
Net capitalised cost	524.2	474.5	441.1

Net capitalised cost related to equity accounted investments as of 31 December 2013 was NOK 5.9 billion, NOK 4.9 billion in 2012 and NOK 5.6 billion in 2011. 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
Year ended 31 December 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
Year ended 31 December 2012					
Exploration expenditures	5.2	4.1	3.8	7.8	20.9
Development costs	45.7	3.2	12.2	28.7	89.8
Acquired proved properties	0.0	0.0	0.0	0.3	0.3
Acquired unproved properties	0.0	0.4	0.0	6.0	6.4
Total	50.9	7.7	16.0	42.8	117.4
Year ended 31 December 2011					
Exploration expenditures	6.6	2.5	1.7	8.0	18.8
Development costs	36.9	2.8	11.1	19.4	70.2
Acquired proved properties	1.7	0.0	0.0	7.6	9.3
Acquired unproved properties	0.1	0.3	5.1	26.2	31.7
Total	45.3	5.6	17.9	61.2	130.0

Expenditures incurred in Oil and Gas Development Activities related to equity accounted investments in 2013 and 2012 were NOK 0.4 billion, and NOK 0.3 billion in 2011.

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*. The figures in the "other" lines relate to gains and losses from commodity based derivatives, transportation and processing costs within the upstream segments, upstream business administration and business development as well as gains and losses from sales of oil and gas interests.

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
Year ended 31 December 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	(22.3)	(1.5)	(3.9)	(4.3)	(32.0)
Depreciation, amortisation and net impairment losses	(32.2)	(2.4)	(13.3)	(16.2)	(64.1)
Other expenses	(5.1)	(1.6)	(0.5)	(9.3)	(16.5)
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
Year ended 31 December 2012					
Sales	0.2	6.1	10.3	5.2	21.8
Transfers	212.6	6.8	27.3	20.5	267.2
Other revenues	7.9	1.3	0.2	1.0	10.4
Total revenues	220.7	14.2	37.8	26.7	299.4
Exploration expenses	(3.5)	(3.6)	(3.4)	(7.6)	(18.1)
Production costs	(22.2)	(1.1)	(3.5)	(3.9)	(30.7)
Depreciation, amortisation and net impairment losses	(29.8)	(3.0)	(10.7)	(12.5)	(56.0)
Other expenses	(3.6)	(1.9)	(0.5)	(6.8)	(12.8)
Total costs	(59.1)	(9.6)	(18.1)	(30.8)	(117.6)
Results of operations before tax	161.6	4.6	19.7	(4.1)	181.8
Tax expense	(115.7)	(2.0)	(10.8)	3.1	(125.4)
Results of operations	45.9	2.6	8.9	(1.0)	56.4
Net income from equity accounted investments	0.1	0.5	0.0	0.8	1.4

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year ended 31 December 2011					
Sales	0.6	5.1	4.9	0.8	11.4
Transfers	203.6	6.1	23.1	15.1	247.9
Other revenues	7.9	0.4	0.0	13.8	22.1
Total revenues	212.1	11.6	28.0	29.7	281.4
Exploration expenses	(5.1)	(2.5)	(2.0)	(4.2)	(13.8)
Production costs	(20.4)	(1.3)	(3.0)	(2.9)	(27.6)
Depreciation, amortisation and net impairment losses	(29.7)	(2.8)	(6.5)	(4.5)	(43.5)
Other expenses	(4.3)	(2.4)	(0.5)	(4.8)	(12.0)
Total costs	(59.5)	(9.0)	(12.0)	(16.4)	(96.9)
Results of operations before tax	152.6	2.6	16.0	13.3	184.5
Tax expense	(112.6)	(3.4)	(9.8)	2.3	(123.5)
Results of operations	40.0	(0.8)	6.2	15.6	61.0
Net income from equity accounted investments	0.1	0.5	0.0	0.4	1.0

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 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	-	-	-	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
At 31 December 2012					
Consolidated companies					
Future net cash inflows	1,812.8	138.6	203.4	228.5	2,383.3
Future development costs	(196.1)	(39.6)	(16.2)	(41.2)	(293.1)
Future production costs	(499.1)	(39.8)	(55.4)	(90.9)	(685.2)
Future income tax expenses	(862.7)	(15.0)	(48.9)	(25.1)	(951.7)
Future net cash flows	254.9	44.2	82.9	71.3	453.3
10 % annual discount for estimated timing of cash flows	(113.2)	(25.0)	(27.6)	(34.7)	(200.5)
Standardised measure of discounted future net cash flows	141.7	19.2	55.3	36.6	252.8
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	1.0	1.0
Total standardised measure of discounted future net cash flows including equity accounted investments	141.7	19.2	55.3	37.6	253.8
At 31 December 2011					
Consolidated companies					
Future net cash inflows	1,781.7	102.7	227.0	245.6	2,357.0
Future development costs	(156.5)	(17.0)	(23.3)	(39.2)	(236.0)
Future production costs	(484.6)	(23.8)	(51.3)	(84.3)	(644.0)
Future income tax expenses	(851.8)	(18.2)	(51.8)	(36.8)	(958.6)
Future net cash flows	288.8	43.7	100.6	85.3	518.4
10 % annual discount for estimated timing of cash flows	(120.0)	(19.5)	(38.6)	(38.2)	(216.3)
Standardised measure of discounted future net cash flows	168.8	24.2	62.0	47.1	302.1
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	2.5	2.5
Total standardised measure of discounted future net cash flows including equity accounted investments	168.8	24.2	62.0	49.6	304.6

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK billion)	2013	2012	2011
Consolidated companies			
Standardised measure at beginning of year	252.8	302.1	202.4
Net change in sales and transfer prices and in production (lifting) costs related to future production	(24.0)	9.6	324.2
Changes in estimated future development costs	(54.9)	(63.7)	(51.7)
Sales and transfers of oil and gas produced during the period, net of production cost	(243.2)	(275.1)	(243.0)
Net change due to extensions, discoveries, and improved recovery	10.6	11.1	30.6
Net change due to purchases and sales of minerals in place	(33.9)	(13.4)	(1.9)
Net change due to revisions in quantity estimates	126.5	114.3	110.8
Previously estimated development costs incurred during the period	95.1	88.7	69.6
Accretion of discount	81.5	84.4	56.4
Net change in income taxes	78.2	(5.2)	(195.3)
Total change in the standardised measure during the year	35.9	(49.3)	99.7
Standardised measure at end of year	288.7	252.8	302.1
Equity accounted investments			
Standardised measure at end of year	4.7	1.0	2.5
Standardised measure at end of year including equity accounted investments	293.4	253.8	304.6

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.

8.1.28 Subsequent events

On 10 March 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.

The errors relate to the following three matters:
1. use of reliability intervals for value-in-use estimates in impairment testing of non-financial assets, which in the FSA's view is not in accordance with IFRS;
2. CGU identification for unconventional onshore assets, specifically the Marcellus shale play, which in the FSA's view should be split into more than one CGU for impairment testing; and
3. redefinition of the CGU containing the Cove Point capacity contracts and establishment of a separate onerous contract provision, which in the FSA's view should have been done in a financial period prior to the first quarter 2013 when Statoil provided for these take-or-pay capacity contracts in full.

For the matters described under 1 and 2 above, Statoil has accepted the FSA's interpretations and has applied such interpretations in preparing its Consolidated financial statements as of and for the year ended 31 December 2013. Statoil's note 2 *Significant accounting policies* reflects the group's revised policy application in these two matters. Statoil has not restated prior period financial statements for either 2011 or 2012 as the impact of these two matters have been evaluated as immaterial under both IAS 8 and relevant SEC guidance. Hence there is no catch-up effect in the Consolidated financial statements for 2013.

For the matter described under 3 above, Statoil does not accept the FSA's conclusion. The company has been ordered by the FSA 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 circumstance shall be given in notes to the accounts.*" 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. Accepting the FSA's order would involve recognising a provision within *Net operating income* in an earlier reporting period, rather than in the first quarter of 2013. As the contracts have now been fully provided for in the first quarter 2013, there would be no impact on Statoil's equity at 31 December 2013.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. If a separate onerous contract provision were to be recognised in a period prior to the first quarter 2013, Statoil's reading is that the second quarter of 2011 would be most relevant. On this basis, the following tables show the potential accounting impact of the FSA's Cove Point related order on the Consolidated statement of income and on *Shareholders' equity* for the annual accounts of 2011, 2012 and 2013.

(in NOK billion)	As earlier reported 2011	Cove Point provision	If adjusted 2011
Operating expenses	(59.7)	(7.2)	(66.9)
Selling, general and adminstrative expenses	(13.2)	0.6	(12.6)
Net operating income	211.8	(6.6)	205.2
Income before tax	213.8	(6.6)	207.2
Income tax	(135.4)	0.7	(134.7)
Net income	78.4	(5.9)	72.5
Shareholder's equity	278.9	(5.9)	273.0

(in NOK billion)	As earlier reported 2012	Cove Point provision	If adjusted 2012
Operating expenses	(61.2)	1.1	(60.1)
Selling, general and adminstrative expenses	(11.1)	(0.1)	(11.2)
Net operating income	206.6	1.0	207.6
Income before tax	206.7	1.0	207.7
Income tax	(137.2)	(0.1)	(137.3)
Net income	69.5	0.9	70.4
Shareholder's equity	319.2	(5.0)	314.2

(in NOK billion)	As earlier reported 2013	Cove Point provision	If adjusted 2013
Operating expenses	(75.0)	6.1	(68.9)
Selling, general and adminstrative expenses	(9.2)	(0.5)	(9.7)
Net operating income	155.5	5.6	161.1
Income before tax	138.4	5.6	144.0
Income tax	(99.2)	(0.6)	(99.8)
Net income	39.2	5.0	44.2
Shareholder's equity	355.5	(0.0)	355.5

Kai Kos Dehseh oil sands swap agreement

In January 2014 Statoil and its partner PTTEP entered into an agreement to swap the two parties' respective interests in the Kai Kos Dehseh oil sands project in Alberta, Canada. Statoil will pay a balancing cash consideration of USD 0.2 billion in addition to a working capital adjustment from the agreed economic date, 1 January 2013. Statoil will continue as operator and 100% owner of the Leismer and Corner development projects, while PTTEP will be the 100% owner of the Thornbury, Hangingstone and South Leismer areas. The agreement is subject to customary regulatory approvals in Canada. The transaction will be recognised in the Development and Production International segment at the time of closing, which is expected in the third quarter of 2014.

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 2013 and 2012 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the two-year period ended 31 December 2013. 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 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 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 audit provides 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 2013 and 2012, and the results of their operations and their cash flows for each of the years in the two-year period ended 31 December 2013, 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.

As discussed in Notes 8.1.2 and 8.1.3 to the consolidated financial statements, Statoil ASA elected to change its policy for presentation of changes in current financial investments in the statement of cash flows in 2012 and classification of certain royalty amounts in 2013, respectively.

We also have audited the adjustments described in Notes 8.1.2 and 8.1.3 that were applied to restate the 31 December 2011 consolidated financial statements for the change in Statoil ASA's policy for presentation of changes in current financial investments in the statement of cash flows in 2012 and classification of certain royalty amounts in 2013, respectively. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 31 December 2011 consolidated financial statements of the Company other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 31 December 2011 consolidated financial statements taken as a whole.

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 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 14 March 2014 expressed an unqualified opinion on the effectiveness of Statoil ASA's internal control over financial reporting.

/s/ KPMG AS

Stavanger, Norway
14 March 2014

8.2.2 Report of Independent Registered Public Accounting Firm

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Statoil ASA

We have audited, before the effects of the adjustments to retrospectively apply the change in accounting described in Note 8.1.2 Significant accounting policies; Changes in accounting policies in 2012, and the reclassifications described in Note 8.1.3 Segments, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the year ended 31 December 2011 (the 2011 financial statements before the effects of the adjustments and reclassifications discussed in Notes 8.1.2. and 8.1.3. are not presented herein). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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 2011 financial statements, before the effects of the adjustments to retrospectively apply the change in accounting and effect of reclassifications described in Notes 8.1.2 and 8.1.3, present fairly, in all material respects, the consolidated results of Statoil ASA's operations and its cash flows for the year ended 31 December 2011, 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 were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively apply the change in accounting described in Note 8.1.2 or the reclassifications in Note 8.1.3 and, accordingly, we do not express an opinion or any other form of assurance about whether such adjustments and reclassifications are appropriate and have been properly applied. Those adjustments and reclassifications were audited by KPMG AS.

/s/ Ernst & Young AS

Stavanger, Norway
13 March 2012

8.2.3 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 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 the Company'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 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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 2013 and 2012 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the years in the two-year period ended 31 December 2013, and our report dated 14 March 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG AS

Stavanger, Norway
14 March 2014

9 Terms and definitions

An overview of organisational abbreviations.

- ACG - Azeri-Chirag-Gunashli
- ACQ - Annual contract quantity
- AFP - Agreement-based early retirement plan
- ÅTS - Åsgard transport system
- APA - Awards in pre-defined areas
- BTC - Baku-Tbilisi-Ceyhan pipeline
- CCS - Carbon capture and storage
- CHP - Combined heat and power plant
- CO_2 - Carbon dioxide
- D&P - Development and production
- DPI - Development and production International
- DPN - Development and production Norway
- DPNA - Development and production North America
- EEA - European Economic Area
- EFTA - European Free Trade Association
- EMTN - Euro medium-term note
- EXP - Exploration
- FCC - Fluid catalytic cracking
- FEED - Front-end engineering design
- FID - Final investment decision
- FPSO - Floating production storage offloading
- GBS - Gravity-based structure
- GDP - Gross domestic product
- GoM - Gulf of Mexico
- GSB - Global strategy and business development
- HSE - Health, safety and environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- IOR - Improved oil recovery
- LNG - Liquefied natural gas
- LPG - Liquefied petroleum gas
- MPR - Marketing, processing and renewable energy
- MPE - Norwegian Ministry of Petroleum and Energy
- NCS - Norwegian continental shelf
- NG - Natural Gas business cluster
- NICO - Naftiran Intertrade Co. Ltd.
- NIOC - National Iranian Oil Company
- NOK - Norwegian kroner
- NO_x- Nitrogen oxide
- OECD - Organisation of Economic Co-Operation and Development
- OPEC - Organization of the Petroleum Exporting Countries
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- PBO - Project benefit obligation
- PDO - Plan for development and operation
- PIO - Plan for installation and operation
- PSA - Production sharing agreement
- 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

- SDAG - Shtokman Development AG
- SDFI - Norwegian State's Direct Financial Interest
- SFR - Statoil Fuel & Retail
- TPD - Technology, projects and drilling
- TSP - Technical service provider
- USD - United States dollar

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 equivalents
- 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.
- Carbon footprint: Total set of greenhouse gas emissions caused directly and indirectly by an individual, organisation, event or product.
- 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.
- FCC (fluid catalytic cracking): A process used to convert the high-boiling hydrocarbon fractions of petroleum crude oils to more valuable gasoline, gases and other products.
- GTL (gas to liquids): The technology used for chemical conversion of natural gas into transportable liquids (diesel and naphtha) and specialty products (base oils).
- 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: An 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.
- 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.
- Rebased production: Equity production is adjusted for full year impact of transactions and redetermination.
- 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.
- Share turnover: Turnover of shares is a measure of stock liquidity calculated by dividing the total number of shares traded over a period by the average number of shares outstanding for the period. The higher the share turnover, the more liquid the share of the company.
- Syncrude: The output from bitumen extra heavy oil upgrader facility used in connection with oil sand production.
- 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).
- Wildcat well: The first well to test a new, clearly defined geological unit (prospect).
- Økokrim: Prosecution of Economic and Environmental Crime in Norway.

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; effects of the Macondo oil spill and future drilling in the Gulf of Mexico; expectations related to our recent transactions and projects, such as the Wintershall agreement, Polarled, our interests in the Marcellus and Eagle Ford shale gas developments in the U.S., the UK Mariner field and the Peregrino field in Brazil, discoveries in the Havis prospect, King Lear, Gina Krog, Johan Sverdrup (formerly Aldous and Avaldsnes) and Skrugard and offshore Tanzania and Brazil; 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 authorized the undersigned to sign this Annual Report on its behalf.

STATOIL ASA
(Registrant)

By: /s/ Torgrim Reitan
Name: Torgrim Reitan
Title: Executive Vice President and Chief Financial Officer

Dated: 21 March 2014

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 replacing the Technical Services Agreement between Gassco AS and Statoil ASA, dated February 27, 2002 (which was previously filed as Exhibit 4(a)(i) to Statoil's Annual Report on Form 20-F for the fiscal year ended December 31, 2001 (File No. 1-15200)).
Exhibit 4(c)	Employment agreement with Helge Lund (English translation) (incorporated by reference to Exhibit 4(c) to Statoil's Annual Report on Form 20-F for the fiscal year ended December 31, 2003 (File No. 1-15200)).
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.*
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.*
Exhibit 15(a)(i)	Consent of KPMG AS.
Exhibit 15(a)(ii)	Consent of Ernst & Young AS.
Exhibit 15(a)(iii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iv)	Report of DeGoyler and MacNaughton.

* Furnished only

The total amount of long-term debt securities of the Registrant and its subsidiaries authorized 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
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	D. Exchange Controls	6.6
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