ANNUAL REPORT /2012

Annual Report on Form 20-F

Statoil

ANNUAL REPORT /2012

Annual Report on Form 20-F

The Annual Report on Form 20-F is our SEC filing for the fiscal year ended December 31, 2012, as submitted to the US Securities and Exchange Commission. The complete edition of our Annual Report is available online at www.statoil.com/2012

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

www.statoil.com

Cover photo: Ole Jørgen Bratland

Annual report on Form 20-F

Cover Page

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, 2012

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
Statoil ASA
Forusbeen 50, N-4035
Stavanger, Norway
Telephone No.: 011-47-5199-0000
Fax No.: 011-47-5199-0050
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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

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

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

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

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

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

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

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

☒ Yes ☐ No

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

☐ Yes ☒ No

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

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

☒ Yes ☐ No

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

☐ Yes ☐ No

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

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

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

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

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

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

Item 17 ☐

Item 18 ☐

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

☐ Yes ☒ No

1 Introduction

1.1 About the report

Statoil's Annual Report on Form 20-F for the year ended 31 December 2012 ("Annual Report on Form 20-F") is available online at www.statoil.com/2012.

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's financial results and cash flows were solid in 2012. Production was up 8%, important strategic progress was made and the balance sheet was further strenghtened.

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

	For the year ended 31 December				
(in NOK billion, unless stated otherwise)	2012	2011	2010	2009	2008
Financial information					
Total revenues and other income	723.4	670.2	529.9	465.4	656.0
Net operating income	206.6	211.8	137.3	121.7	198.8
Net income	69.5	78.4	37.6	17.7	43.3
Bonds, bank loans and finance lease liabilities	101.0	111.6	99.8	96.0	75.3
Net interest-bearing liabilities before adjustments	39.3	71.0	69.5	71.8	46.0
Total assets	784.4	768.6	643.3	563.1	579.2
Share capital	8.0	8.0	8.0	8.0	8.0
Non-controlling interest	0.7	6.2	6.9	1.8	2.0
Total equity	319.9	285.2	226.4	200.1	216.1
Net debt to capital employed ratio before adjustments	10.9%	19.9%	23.5%	26.4%	17.8%
Net debt to capital employed ratio adjusted	12.4%	21.1%	25.5%	27.6%	18.8%
Calculated ROACE based on Average Capital Employed before adjustments	18.7%	22.1%	12.6%	10.6%	21.0%
Operational information					
Equity oil and gas production (mboe/day)	2,004	1,850	1,888	1,962	1,925
Proved oil and gas reserves (mmboe)	5,422	5,426	5,325	5,408	5,584
Reserve replacement ratio (three-year average)	1.0	0.9	0.6	0.6	0.6
Production cost equity volumes (NOK/boe, last 12 months)	42	42	38	35	35
Share information					
Diluted earnings per share NOK	21.60	24.70	11.94	5.74	13.58
Share price at Oslo Stock Exchange on 31 December in NOK	139.00	153.50	138.60	144.80	113.90
Dividend paid per share NOK (1)	6.75	6.50	6.25	6.00	7.25
Dividend paid per share USD (2)	1.21	1.08	1.07	1.04	1.26
Weighted average number of ordinary shares outstanding (in thousands)	3,181,546	3,182,113	3,182,575	3,183,874	3,185,954

(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 2012 dividend for approval at the Annual General Meeting scheduled for 14 May 2013.

(2) USD figure presented using the Central Bank of Norway 2012 year-end rate for Norwegian kroner, which was USD 1.00 = 5.57 NOK. The board of directors will propose the 2012 dividend for approval at the Annual General Meeting scheduled for 14 May 2013.

2 Strategy and market overview

2.1 Our business environment

2.1.1 Market overview

Recovery following the 2008 financial crisis has been muted and fragile. Growth in OECD economies has been low, which has dampened economic activity in the non-OECD area.

Nevertheless, non-OECD expansion continues at a relatively solid pace and supports global economic growth and energy demand.

It became clear in 2012 that the OECD countries' economic recovery from the aftermath of the financial crisis in 2008 will be a long process, involving a fine balance between fiscal tightening and growth stimulus. Debt levels and fiscal deficits are high in key OECD economies and must be brought onto a sustainable path in order to avoid increasing debt servicing costs. At the same time, growth is critical to achieving such a reduction. Statoil therefore believes that it is important to avoid austerity measures that dampen growth too much. Achieving both is a difficult balancing act. Fortunately for global growth and also for global energy demand, growth has persisted in non-OECD economies, which means export opportunities for competitive OECD producers. In total, however, global economic growth was significantly lower in 2012 than in 2011.

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 global weighted geographical point of economic gravity continues to move gradually eastwards and southwards relative to the OECD economies in Europe and North America.

Energy-dependent growth in the non-OECD economies is expected to contribute to growth in global energy demand over the next decade, including oil demand. Statoil's research suggests that annual growth in global oil demand will average 0.9% (~0.8 mbd). As a result of increases in tight oil production and an expected increase in Iraqi production, among other factors, this will mean a medium-term weakening of fundamentals in the global oil market as measured by Opec spare capacity. In the longer term, Statoil expects increased demand for Opec liquids and thereby a larger market share for Opec. Medium-term price development depends on the balance between moderately weakening fundamentals, marginal costs and geopolitical uncertainty premiums due to supply risks.

Global gas demand is expected to increase due to the general increase in energy demand, but also due to the increasing competitiveness of gas in terms of costs and environmental effects. Growth in gas demand is therefore also very dependent on energy and climate policies in key countries and regions. Statoil's internal research suggests that gas demand in Europe and North America will increase by 1-2% per year until 2020, while Asian demand will grow by 4-5% per year in the same period. Both Europe and Asia will depend on imported LNG to meet demand, which will contribute to keeping prices at robust levels. The very low gas prices in North America, which are caused by the development of the shale gas industry, are expected to gradually increase as the market situation normalises, but to remain below European and Asian gas prices.

The global economic situation continues to be fragile, with development in large part 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 average production growth rate is highly competitive, especially in combination with our recent exploration results. Increasing competition, tighter fiscal conditions and increasing costs pose challenges for access to new profitable resources. It is anticipated that oil companies, including Statoil, will continue to respond to these challenges with varying changes in their portfolios, including access to unconventional oil and gas assets, increasing exploration activities and cost and portfolio management actions.

Going forward, fighting decline of legacy fields and increasing technical challenges in new field developments are expected to put upward pressure on capital and operational expenditure. Companies that are at the forefront of efficient resource management and 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 2012 saw strong prices for Brent crude and significant volatility. The refinery margin improved significantly compared to 2011.

Oil prices

The average price for Brent crude in 2012 was close to USD 111.53/bbl, slightly above the 2011 average of USD 111.41/bbl. The 2011 average represented a record-high price for crude, and 2012 set a new record. During the first quarter, Brent prices gradually rose from around USD 110/bbl to USD 130/bbl. Prices then dropped through most of the second quarter before they bottomed out below USD 90/bbl in late June. However, the market quickly recovered and stabilised; prices stayed within a narrow range between USD 105 and 115/bbl through most of the second half-year. With the exception of a few days in June, the market has been in fairly strong backwardation (see section *Terms and definitions*) throughout 2012.

The WTI price started 2012 at around USD 103/bbl and peaked at the end of February at USD 109/bbl. After a strong start, the WTI price began to drop at the beginning of May and bottomed out around USD 78/bbl at the end of June. It recovered during the third quarter, peaking at USD 97/bbl before it stabilised in the range of USD 85-92/bbl. The 2012 average was close to USD 96/bbl.

Geopolitical factors were the main driver for oil prices in 2012. Although Libyan oil production was approaching pre-civil war levels by early spring, a string of production disruptions in smaller producing countries, such as Sudan, South Sudan, Yemen and later Syria, kept oil supplies curtailed.

From the start of the year, the tensions between the Western powers and Iran over Tehran's nuclear programme intensified. Fear of potential air strikes explained much of the strength in prices during early spring. Markets were increasingly worried that the Straits of Hormuz would be blocked in the event of an armed conflict, which could mean that almost 20% of global oil supplies would be unable to exit the Persian Gulf. In addition, a ban was imposed on all imports of Iranian crudes to EU countries, and US sanctions on any bank or financial intermediary that is found to be dealing with the Iranian regime were enacted. As a result, Iranian exports gradually dwindled from almost 2 mb/d in December 2011 to around 1 mb/d in the fourth quarter of 2012.

Saudi Arabia responded to this strong market by producing more oil, touching previous all-time-high production levels around 10 mboe per day during spring 2012. This coincided with the period of the year with lowest demand, and led to an oversupply of crude and briefly brought prices below USD 90/bbl in June.

Prices quickly recovered, however, and Brent stabilised at levels near USD 110/bbl for the remainder of the year. Market fundamentals tightened rapidly as a result of seasonally stronger oil demand, the growing effect of sanctions on Iran, and significant supply loss from field maintenance and weather-related shutdowns in the North Sea, Brazil and the Caspian region. Persistently high Saudi output meant that the effective Opec spare capacity stayed low throughout the year. Rising concern about both short and long-term stability in the Middle East as a result of the Syrian civil war provided price support.

The market for crude oil has remained strong despite weak economic growth performance, especially in the developed world. Growth in oil demand is well below earlier years. Global growth in oil demand in 2012 was about 0.7 million barrels per day (mb/d) or 0.8%, even lower than the weak growth experienced in 2011. Furthermore, the debt crisis in the Eurozone, the lacklustre recovery in the US and slowing growth in China opened up a major downside risk.

Refinery margin

The refinery margin improved significantly in 2012 due to refinery maintenance in Northwest Europe and the east coast of the USA. The lower capacity in the Atlantic Basin contributed especially to high margins during the second and third quarter of 2012. Statoil's refining reference margin was USD 5.5/bbl in 2012 compared to 2.3 in 2011, an increase of 138%. The refining reference margin was USD 3.9/bbl in 2010.

2.1.3 Natural gas prices

Natural gas prices in Europe were 5% higher on average in 2012 than they were in 2011, despite weaker demand. In North America, prices have fallen to their lowest levels of the decade.

Gas prices - Europe

Natural gas prices in Europe were 5% higher on average in 2012 than they were in 2011, despite weaker demand. The continued economic problems in Europe resulted in subdued demand. However, the supply situation was tight across Europe because of declining domestic production and Europe's increased reliance on imported gas.

Coal and carbon prices weakened further in 2012 which has reinforced coal's competitive position relative to gas in power generation. Increased renewable generation, especially in Germany, has also displaced gas demand. Falling gas generation combined with weaker industrial and residential demand has seen overall demand fall by 3% in Europe. The availability of LNG imports to Europe has been constrained due to the strong demand in Asia. Imports of LNG to Europe fell by 25% and imports to Asia rose by 11% in 2012. Following the Fukushima disaster, only two of Japan's 54 nuclear reactors are in operation, so Japan has been reliant on fuel imports, especially LNG, to replace the lost nuclear output. Further potential upside pressure is expected from nuclear outages in South Korea.

Gas prices - North America

The year 2012 was a year of extremes in the North American gas market, having set three records: warmest winter, largest coal-to-gas switching, and highest domestic production. Setting the stage for the year, the mild winter coupled with production growth of 4% compared to 2011 led to record storage inventories coming out of the winter withdrawal season. As a result, prices have fallen to their lowest levels of the decade, averaging just USD 2.60 per million British thermal unit (MMBtu) to date in 2012, down 35% from USD 3.74 per MMBtu in 2011.

One of the warmest summers ever recorded helped to balance the market. In addition to the increased cooling demand, the low gas prices drove gas to outcompete coal for power generation. In 2012, gas demand for power increased by 50 Bcm/a compared to 2011, helping to substantially reduce the oversupply in the US market. In addition, the low price environment and reduced demand for imported gas in the US has reduced incentives for drilling Canadian gas, leading to a 10 Bcm/a decline in production. Looking ahead, the number of gas rigs has fallen over 50% to just 420 rigs, suggesting a potential future decline in domestic production going forward. Initial signs of a tightening market are present, which is something not seen since 2009. However, low-cost supply remains abundant, which could serve to slow or prevent any increase in price.

The very low gas prices in North America are expected to gradually increase as the market situation normalises, but to remain below European and Asian gas prices.

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 immediate priorities remain to conduct safe, reliable operations with zero harm to people and the environment, and to deliver profitable production growth.

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

- Revitalising Statoil's legacy position on the Norwegian continental shelf (NCS)
- Building offshore clusters
- Developing into a leading exploration company
- Increasing our activity in unconventional resources
- 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.

Revitalising Statoil's legacy position on the NCS

The NCS remains a prolific and productive oil and gas province where only half of the resources have been produced. The Havis discovery in 2012 has increased expectations of the exploration potential of the Barents Sea. Furthermore, the Johan Sverdrup discovery and appraisal have stimulated efforts to make additional discoveries in the more mature North Sea. Between now and 2020, Statoil aims to bring on stream new production from a combination of:

- Developments of larger discoveries, including Aasta Hansten, Gina Krog (formerly Dagny), Skrugard/Havis and Johan Sverdrup fields, which are expected to contribute considerably to Statoil's total production towards the end of this decade.
- 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 increase oil recovery on the NCS to 60% over time.

Building offshore clusters

Statoil's international oil and gas production has increased from around 100,000 boe to around 650,000 boe per day since the year 2000. Statoil has established a presence in many 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, 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 we continue to work on ramping up Peregrino production. In the future, we will focus on further developing the Peregrino area and maturing the existing exploration portfolio. In 2012, we extended our exploration portfolio and made several new discoveries.
- **Angola**; where we are working to optimise our non-operated portfolio. In 2012, Pazflor was successfully ramped up and the PSVM (the Plutao, Saturno, Venus and Marte oilfields) project came on stream in December. We continue to mature our exploration acreage, gathering seismic data for parts of our pre-salt acreage that was awarded in 2011.
- **Tanzania**; which emerged as a new potential cluster in 2012, and where we have made several large gas discoveries.

Developing into a leading exploration company

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

- **Early access at scale**: We have focused on access to frontier acreage over the last few years and have been an early mover in several areas. The ongoing negotiations with Rosneft for access to three blocks in the Sea of Okhotsk and one block in the Russian Barents Sea represent a potential breakthrough for future exploration success in Russia.
- **Exploit core positions**: We have secured more acreage in potential clusters such as the US Gulf of Mexico. Furthermore, on the NCS, we have maintained high focus on growth and ILX wells with significant potential. Acreage applications in both the awards in predefined areas (APA) and 22nd license round have given Statoil access to promising new high-value prospects.
- **Drill more significant wells**: We made several significant discoveries in 2012, including in Norway (Havis and King Lear), Tanzania (Zafarani and Lavani) and in Brazil (Pão de Açúcar).

To replicate this success, we aim to continue balancing our exploration portfolio in potential offshore clusters with frontier exploration and more high-impact wells to unlock new plays.

Stepping up our activity in unconventional resources

Our unconventional resources portfolio is diverse. It includes leases in the shale gas and oil basins of Marcellus, Eagle Ford and Bakken in the US. In addition, we are maturing our Alberta, Canada Kai Kos Deh Seh and Corner oil sands projects. In 2012, we secured operational control over leases in Eagle Ford and Marcellus to further enhance our control over these assets.

Our priorities in unconventional resources include:

- Delivering profitable ramp up
- Developing and executing a technology development programme for unconventional resources
- Expanding acreage holdings around our current upstream positions
- Further building for the long term through early access to land that can be developed in due course

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 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 access exploration acreage and unconventional reserves, secure operatorships, build cluster positions, manage asset maturity, de-risk positions and demonstrate the intrinsic value of the portfolio. Transactions in 2012 include the NCS asset package sale to Centrica and the divestment of Statoil Fuel and Retail (both transactions are closed) and Wintershall (pending governmental approval). They further underpin our ability to redeploy capital and create value.

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 2012, we commissioned the offshore wind Sheringham Shoal development in the UK. We acquired another UK offshore wind development project, Dudgeon, to utilise the experience we had gained to develop this and other new projects. 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. We are maturing two carbon capture projects at present - the large-scale Technology Centre Mongstad testing facility and the full-scale Carbon Capture Mongstad plant.

2.3 Our technology

We continually 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 will strive to achieve over the next decade.

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, value creation and growth.

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 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

Statoil's defined ambition is to grow equity production towards 2020. Equity production in 2013 is estimated to be lower than the 2012 level. Organic capital expenditures for 2013 are estimated at around USD 19 billion.

Organic capital expenditures for 2013 (i.e. excluding acquisitions and capital leases) are estimated at around USD 19 billion.

Statoil will continue to mature its large portfolio of exploration assets and expects to complete around 50 wells in 2013, with a total exploration activity level of around USD 3.5 billion, excluding signature bonuses.

Our ambition for unit of production cost continues to be in the top quartile of our peer group.

Planned maintenance is expected to have a negative impact of around 45 mboe per day on equity production for the full year 2013, most of which consists of liquids.

Statoil's defined ambition is to grow equity production towards 2020. The growth is expected to come from new projects. The growth towards 2020 will not be linear, and equity production in 2013 is estimated to be lower than the 2012 level. The impact on production of the closing of the Wintershall transaction will be around 40 mboe per day. Growth in US onshore gas production is expected to be around 25 mboe lower per day than previously assumed. In Europe, as part of the value-over-volume strategy, the company produced somewhat higher gas volumes in 2012 than previously assumed, which reduces the estimated 2013 gas production by approximately 15 mboe per day. The 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. In addition, the recent terror attack gives rise to uncertainty about production from In Amenas in Algeria.

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.

We have grown in parallel with the Norwegian oil and gas industry, which dates back to the late 1960s. Initially, our operations primarily focused on exploration for and the production and development 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.

We 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, we sold all of our remaining shares in Statoil Fuel & Retail ASA.

We are 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 an upstream, technology-driven energy company that is primarily engaged in oil and gas exploration and production activities.

Statoil's headquarters are in Norway. We have business operations in 35 countries and territories and have approximately 23,000 employees worldwide.

Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian act relating to public limited liability companies (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 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 2012, 33% 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 the second-largest supplier of natural gas to the European market. Statoil also has substantial processing and refining operations. The company is contributing to the development of new energy resources, has ongoing activities in offshore wind, and is at the forefront of the implementation of technology for carbon capture and storage (CCS).

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 and unconventional oil and gas and oil sands in the US and Canada. In this connection, we aim to further strengthen our capabilities in deep water, unconventional gas operations and carbon-efficient oil sands extraction.

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 R&D. 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 activities (M&A) 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
After implementing the new corporate structure on 1 January 2011, Statoil has reported 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); Fuel & Retail (FR) (until 19 June 2012, when the segment was sold); and Other.

The Other reporting segment includes activities in TPD, GSB and corporate staffs and services. Activities relating to the Exploration 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 area. The geographical areas are defined by country and continent. They consist of Norway, Eurasia excluding Norway, Africa, and the Americas.

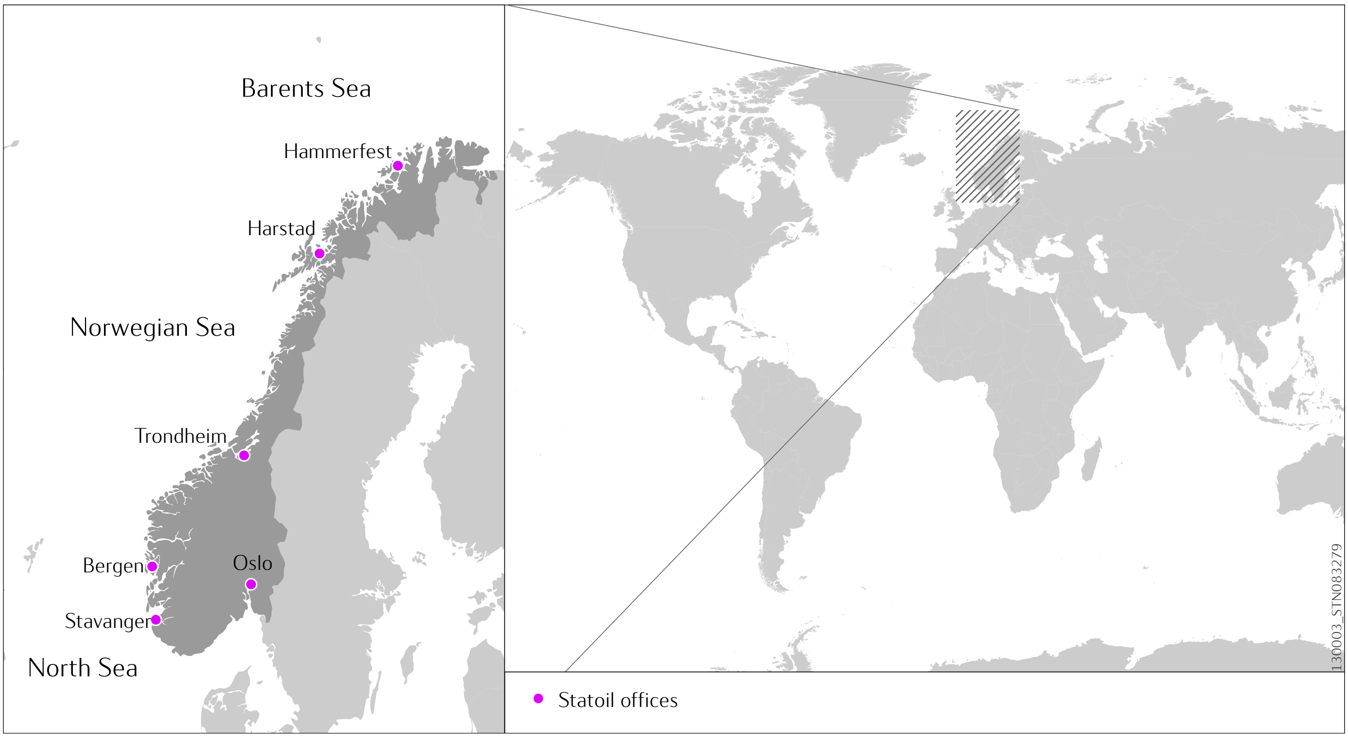
3.5 Development and Production Norway (DPN)

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).

We have 42 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 1,335 mboe per day in 2012. That was about 73% of Statoil's total entitlement production and 67% of Statoil's equity production. In 2012, our daily production of oil and natural gas liquids (NGL) on the NCS was 624 mboe, while our average daily gas production on the NCS was 113 mmcm (4.0 bcf). Acting as operator, Statoil is responsible for approximately 71% of all oil and gas production on the NCS.



In 2012, DPN organised the production operations into four business clusters: Operations North, Operations North Sea West, Operations North Sea East and Operations South. The Operations South and Operations North Sea West and East clusters cover our licences in the North Sea. Operations North covers our licences in the Norwegian Sea and in the Barents Sea, while partner-operated fields cover the entire NCS and are included internally in the Operations South business cluster.

From 1 January 2013, DPN has split the business cluster Operations North into two independent business clusters: Operations North (located in Harstad) and Operations Mid-Norway (located in Stjørdal, near Trondheim). This is a strategically important milestone in relation to expanding our business in the northern region of Norway. The (new) Operations North cluster will include 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 will follow up Statoil's activity in the Norwegian Sea as well as fields under development in this region.

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 making active efforts 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 2012:

- Production start-up of Visund South, the first fast-track project in production on the NCS, and Skarv (operated by BP).
- The agreement with Centrica to sell interests in certain licences on the NCS was closed in April 2012. The transaction was recognised in the second quarter of 2012. The gain from the transaction is NOK 7.5 billion.
- Statoil entered into an agreement with Wintershall to exit the Brage licence and transfer the operatorship to Wintershall, farm down in the Gjøa licence - including the Vega and Vega South satellite fields - and enter the Edvard Grieg licence. The cash consideration amounts to USD 1.45 billion. The transaction is expected to be closed during the second half of 2013. The transaction is subject to governmental approval.
- Major discoveries in the Havis prospect in the Barents Sea and King Lear in the North Sea.
- Extensive appraisal drilling still ongoing in the Johan Sverdrup area; several successful appraisal wells were drilled during 2012.
- Ten planned turnarounds were finalised during 2012.
- High project activity; investment decisions were made to develop 20 projects (including IOR projects).
- Submitted plan for development and operation (PDO) for Gina Krog (formerly Dagny), Aasta Hansteen and Ivar Aasen (operated by Det Norske) to the Norwegian Ministry of Petroleum and Energy.
- Approved PDO for the Svalin fast-track project in the North Sea.

3.5.2 Fields in production on the NCS

In 2012, our total production of entitlement liquids and gas was 1,335 mboe per day, compared to 1,316 mboe per day in 2011.

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 2012, 2011 and 2010. Field areas are groups of fields operated as a single entity.

	For the year ended 31 December								
	2012			2011			2010		
Area production	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe
Operations North	180	23	326	214	24	363	183	24	333
Operations North Sea West	163	16	264	177	15	273	228	17	336
Operations North Sea East	140	39	387	147	25	306	138	32	337
Operations South (ex Partner Operated Fields)	93	13	177	112	16	210	119	16	220
Partner Operated Fields	49	21	181	43	19	165	36	18	147
Total	624	113	1,335	693	99	1,316	704	106	1,374

The following table shows the NCS production by fields and field areas in which we were participating as of 31 December 2012. Field areas are groups of fields operated as a single entity.

Business cluster	Georgraphical area	Statoil's equity interest in %[1]	Operator	On stream	Licence expiry date	Average daily production in 2012 mboe/day
Operations North						
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	**124.0**
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	**52.9**
Snøhvit	The Barents Sea	33.53	Statoil	2007	2035	**36.7**
Kristin	The Norwegian Sea	55.30	Statoil	2005	2033 [2]	**31.8**
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2022 [3]	**21.6**
Morvin	The Norwegian Sea	64.00	Statoil	2010	2027	**21.5**
Alve	The Norwegian Sea	85.00	Statoil	2009	2029	**13.2**
Norne	The Norwegian Sea	39.10	Statoil	1997	2026	**6.5**
Heidrun	The Norwegian Sea	12.41	Statoil	1995	2024 [4]	**6.3**
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 & 2023 [5]	**4.6**
Yttergryta	The Norwegian Sea	45.75	Statoil	2009	2027	**3.7**
Urd	The Norwegian Sea	63.95	Statoil	2005	2026	**3.6**
Total Operations North						**326.4**
Operations North Sea West						
Gullfaks	The North Sea	70.00	Statoil	1986	2016	**90.9**
Kvitebjørn	The North Sea	58.55	Statoil	2004	2031	**85.6**
Grane	The North Sea	36.66	Statoil	2003	2030	**44.2**
Visund	The North Sea	53.20	Statoil	1999	2023	**11.9**
Gimle	The North Sea	65.13	Statoil	2006	2016	**6.7**
Vilje	The North Sea	28.85	Statoil	2008	2021	**6.7**
Volve	The North Sea	59.60	Statoil	2008	2028	**6.3**
Brage	The North Sea	32.70	Statoil	1993	2015 [6]	**5.3**
Veslefrikk	The North Sea	18.00	Statoil	1989	2015	**3.2**
Huldra	The North Sea	19.88	Statoil	2001	2015	**2.0**
Glitne	The North Sea	58.90	Statoil	2001	2013	**1.0**
Vale	The North Sea	28.85	Statoil	2002	2021	**0.2**
Heimdal	The North Sea	29.44	Statoil	1985	2021 [7]	**0.0**
Total Operation North Sea West						**264.0**
Operations North Sea East						
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030	**181.0**
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030	**48.8**
Oseberg	The North Sea	49.30	Statoil	1988	2031	**110.6**
Fram	The North Sea	45.00	Statoil	2003	2024	**23.9**
Vega Unit	The North Sea	54.00	Statoil	2010	2035 [6]	**20.1**
Tune	The North Sea	50.00	Statoil	2002	2032	**2.6**
Total Operation North Sea East						**387.0**

Business cluster	Georgraphical area	Statoil's equity interest in %(1)	Operator	On stream	Licence expiry date	Average daily production in 2012 mboe/day
Operations South (ex Partner Operated Fields)						
Sleipner West	The North Sea	58.35	Statoil	1996	2028	**74.0**
Sleipner East	The North Sea	59.60	Statoil	1993	2028	**15.4**
Gungne	The North Sea	62.00	Statoil	1996	2028	**9.3**
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026	**31.6**
Statfjord Øst	The North Sea	31.69	Statoil	1994	2026 (8)	**2.8**
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026	**0.7**
Sygna	The North Sea	30.71	Statoil	2000	2026 (8)	**0.3**
Snorre	The North Sea	33.32	Statoil	1992	2015 (9)	**26.2**
Vigdis area	The North Sea	41.50	Statoil	1997	2024	**14.4**
Tordis area	The North Sea	41.50	Statoil	1994	2024	**1.8**
Total Operations South (ex Partner Operated Fields)						**176.5**
Partner Operated Fields						
Ormen Lange	The Norwegian Sea	28.92	Shell	2007	2041	**120.1**
Gjøa	The North Sea	20.00	GDFSuez	2010	2028 (6)	**24.7**
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	**16.4**
Sigyn	The North Sea	60.00	ExxonMobil	2002	2018	**9.2**
Marulk	The North Sea	11.78	Eni Norge AS	2012	2025	**5.7**
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	**2.5**
Vilje	The North Sea	28.85	Marathon Oil	2008	2021	**2.0**
Skirne	The North Sea	10.00	Total	2004	2025	**0.5**
Total Partner Operated Fields						**181.1**
Total Operations South (incl Partner Operated Fields)						**357.6**
Total						**1,335.0**

(1) Equity interest as of 31 December 2012.
(2) PL134B expires in 2027 and PL199 expires in 2033.
(3) PL092 expires in 2020 and PL121 expires in 2022.
(4) Re-determination at Heidrun with makeup periods in 2012. Statoil owner shares: Jan-Feb: 38.5644%; Mar-Jun: 13.27633%; Jun: 13.11821%; Jul-Dec: 0%.
(5) PL107 expires in 2021 and PL132 expires in 2024.
(6) In 2012, Statoil entered an agreement with Wintershall to exit the Brage licence and transfer the operatorship to Whitershall, farm down in the Gjøa licence, including the Vega and Vega South satellite fields (Vega Unit). Closing of the transaction is expected to take place during the second half of 2013. The transaction is subject to governmental approval.
(7) PL036 expires in 2021 and PL102 expires in 2025. The owner share of the topside facilities is 39.44%, however the owner share of the reservoir and production is 29.44%.
(8) PL037 expires in 2026 and PL089 expires in 2024.
(9) PL089 expires in 2024 and PL057 expires in 2015.

The following sections provide information about the main producing assets. See the section *Financial review - Operating and financial review 2012 - DPN profit and loss analysis* for a discussion of results of operations for 2012, 2011 and 2010.

3.5.2.1 Operations North

The main producing fields in the Operations North area are Åsgard, Heidrun, Kristin, Tyrihans, Snøhvit, Mikkel and Njord.

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%) was developed with 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 ÅTS to the gas processing facility at Kårstø.

Tyrihans (Statoil interest 58.84%) was producing from nine wells by the end of 2012. In addition, gas is injected into two injection wells via Åsgard B. The Tyrihans development project was completed in 2012.

Snøhvit (Statoil interest 33.53%) is the first field to be developed in the Barents Sea. All the offshore installations are subsea, which makes Snøhvit one of the first major developments without production facilities offshore. The natural gas, which is transported to shore through a 143-kilometre-long pipeline, is landed on Melkøya, where it is processed at our LNG plant. The LNG was shipped to customers in Europe, the US and Asia in tankers in 2012.

The LNG plant suffered operational challenges in 2012, mainly in relation to the pre-treatment systems on Melkøya. In the immediate future, the Snøhvit licence will focus on optimising and upgrading the existing LNG facility (Train I) and further developing Snøhvit through planning and mobilising for an improvement project. The main objectives of the project are to find a long-term solution to increase production efficiency and gas export flexibility, thereby ensuring optimal LNG export from the facilities.

The owners in the Snøhvit licence have decided to stop work on a possible capacity increase of the onshore facility on Melkøya. The licence has concluded that the current gas discoveries do not provide a sufficient basis for further capacity expansion.

3.5.2.2 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.

Kvitebjørn (Statoil interest 58.55%). The Kvitebjørn platform processing facilities will be expanded by a compressor module. Re-compression of the gas is expected to increase the expected production of gas and condensate, thereby increasing the recovery rate from 56% to an estimated 71%. Offshore installation of the compressor module will take place in 2013.

Gullfaks (Statoil interest 70.00%) has been developed with three large concrete production platforms. Oil is loaded directly 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.

In late 2010, there was a strong reduction in water injection on Gullfaks with subsequent reduced production in order to maintain the pressure balance. Oil production has gradually increased during recent years. The increased production in 2012 is due to new production wells in the satellites' area and better performance than anticipated on the main field as a result of optimised reservoir management. The drilling operations on the satellites will continue with two mobile rigs in 2013.

Several large projects have been approved on Gullfaks in 2012. The most notable are the Gullfaks South IOR (improved oil recovery) project, consisting of two well templates and six wells, the Gullfaks C subsea gas precompression project and the Gullfaks B drilling upgrade. The high activity level is expected to continue in 2013.

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.

Heimdal (Statoil interest 29.44%). The Heimdal Gas Centre in production licence PL036 is a hub for the processing and distribution of gas. It consists of an integrated steel platform and a riser platform.

In May 2012, Statoil experienced a large gas leak at the Heimdal platform. During a routine operation, a valve was overloaded, causing gas to flow into the surrounding area. There were no injuries to personnel, and all emergency procedures were followed successfully. In Statoil's own investigation report, the gas leak was classified as very serious. The Petroleum Safety Authority (PSA) also conducted an investigation into the incident and concluded that it had major accident potential. PSA has given Statoil notification of an order based on its investigation. Statoil implemented four immediate measures after the incident. These measures involve improving the technical design and updating system drawings, as well as improvements in planning and risk assessment.

Glitne (Statoil interest 58.90%) came on stream in 2001, and the intention was to produce for 26 months. The production period has been significantly extended over the years, and in 2012, twelve years later, the partnership decided to shut down the field. There will be production volumes from Glitne until the shutdown process is started during the first quarter of 2013. The decommissioning on the field is expected to be carried out during the period from the second half of 2013 until 2015, and it is considered to be relatively uncomplicated compared to other larger fields. Due to the concept, which is a floating production ship, the shutdown and final disposal costs are estimated to be in the range of NOK 2 billion. The total production from Glitne has amounted to 55 million barrels of oil, which is more than double the original estimate.

3.5.2.3 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).

Many significant investment decisions were taken during 2012, including the Fram H-Nord fast-track development project.

In 2012, Oseberg was awarded the Norwegian Petroleum Directorate's prize for improved oil recovery (IOR) for its work on increasing recovery by means of gas injection. Both the Oseberg and Troll areas have significant prospective potential and several IOR projects are under evaluation.

Troll (Statoil interest 30.58%) is the largest gas field on the NCS and a major oilfield. 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.

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, and gas is exported through the Oseberg gas transportation system to Heimdal and from there to the market.

3.5.2.4 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 field is under development. It will be tied into Sleipner.

The **Snorre** field (Statoil interest 33.32%) has been developed with two floating platforms and one subsea production system connected to one of the platforms (Snorre B). 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 with three fully integrated platforms supported by gravity-based structures with concrete storage cells and an offshore loading system. The Norwegian authorities have granted a licence extension for the Statfjord area from 2020 until 2026. The current plan is that Statfjord A production will shut down by the end of 2016, while Statfjord B and Statfjord C will continue production until 2025. The **Statfjord satellites** consist of Statfjord North (Statoil interest 21.88%), Statfjord East (31.69%) and Sygna (30.71%). These satellites are all developed with subsea templates tied back to Statfjord C and they are expected to produce until 2025.

3.5.2.5 Partner-operated fields

Partner-operated fields account for approximately 14% of our total oil and gas production on the NCS. The main producing fields are Ormen Lange, Ekofisk and Gjøa.

The organisation that is responsible for follow-up of Statoil's total portfolio of partner-operated fields on the NCS is organised under Operations South and located in Stavanger.

Ormen Lange (Statoil interest 28.916%), 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.

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 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 20.00%) is operated by GDF SUEZ. Gjøa has been developed with 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, Statoil entered into an agreement with Wintershall, including a farm down in the Gjøa licence from 20% to 5% effective from 1 January 2013, pending government approval.

Skarv (Statoil interest 36.17%) is an oil and gas field located in the Norwegian Sea, with BP as operator. The field has been developed with an FPSO vessel 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 on 31 December 2012 and it is currently ramping up production.

3.5.3 Exploration on the NCS

The successful exploration results achieved in 2011 continued into 2012.

The successful exploration results achieved in 2011 continued into 2012, with another major oil discovery in the Barents Sea, Havis, in the vicinity of the Skrugard well. A successful appraisal well was drilled on the Skrugard discovery, confirming the resources and quality of the reservoir. A major gas/condensate discovery was made in the southern part of the North Sea, at King Lear.

In 2012, comprehensive appraisal continued of the giant Johan Sverdrup discovery, previously named Aldous/Avaldsnes. Appraisal drilling confirmed the resource potential and will continue in 2013.

Statoil was awarded ownership interests in 14 production licences in the 2012 annual awards of pre-defined areas (APA), including seven operatorships. In the North Sea, we will be the operator in five of eight licences awarded, and in one of four licences in the Norwegian Sea, while we will operate one of two licences in the Barents Sea. In the 22nd licencing round the main focus was on the Barents Sea, and awards are expected in the third quarter of 2013.

The table below shows the exploration and development wells drilled on the NCS in the last three years. The number decreased from 25 exploration wells and four exploration extensions completed in 2011 to 19 exploration wells and one exploration extension of production wells completed in 2012. The planned number of wells for 2012 was of the same order as for 2011, but due to the late arrival of contracted drilling rigs, three wells have been postponed until 2013.

	2012	2011	2010
North Sea			
Statoil operated exploratory	8	13	5
Statoil operated development	59	61	59
Partner operated exploratory	6	5	7
Partner operated development	12	12	11
Norwegian Sea			
Statoil operated exploratory	1	2	2
Statoil operated development	18	14	14
Partner operated exploratory	2	2	3
Partner operated development	7	6	6
Barents Sea			
Statoil operated exploratory	2	2	0
Statoil operated development	0	0	0
Partner operated exploratory	0	1	0
Partner operated development	0	0	0
Totals			
Exploratory	19	25	17
Exploration extension wells	1	4	4
Development wells	96	93	90

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 2011	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	128,939	41,009	(7,235)	466	225	172	14	7
North Sea	55,043	16,427	699	290	125	99	8	5
Norwegian Sea	52,669	15,084	(4,809)	126	71	52	4	1
Barents Sea	21,227	9,498	(3,125)	50	29	21	2	1

North Sea

In the North Sea, Statoil participated in 14 exploration wells and operated eight of them. Six of the Statoil-operated wells and three of the partner-operated wells were announced as discoveries. The main activity in this area has been the appraisal of the Johan Sverdrup discovery. One of the wells confirmed additional resources in a separate segment on the northern flank of the discovery. The appraisal drilling will continue in 2013.

Statoil made another major discovery in the mature Central Graben area in the southern part of the North Sea. Gas and condensate were confirmed in the King Lear prospect in Block 2/4, located between the producing Ula and Ekofisk fields. Several other prospects have been identified within Block 2/4. These prospects are high temperature/high pressure prospects and are expected to be drilled in the coming years. Rig capacity has been secured for further exploration drilling in 2014.

In the North Sea, both the number of licences with a Statoil share and the size of the licensed acreage increased in 2012.

Norwegian Sea
Exploration activity was limited in the Norwegian Sea in 2012, and there was a net reduction of Statoil equity acreage from 2011 to 2012. This reflects an optimisation of the portfolio based on costs compared to expected prospectivity. The number of licences with a Statoil share also decreased. Statoil drilled one well in the Norne area, Jette, which was a non-commercial discovery. In addition, two partner-operated wells were drilled. One of them was a minor gas discovery, located approximately five kilometres east of the Marulk field.

Barents Sea
In the Barents Sea, the main area for exploration activities has been the Statoil-operated Skrugard licence in the Bjørnøya South basin. Statoil has drilled two wells as operator for the Skrugard licence, and made another major discovery at the Havis prospect. The drilling of the first appraisal well at the major Skrugard discovery last year confirmed the size and the reservoir quality.

A drilling campaign of nine wells will start in the Barents Sea in 2013. Four of them will be located in the Skrugard area, three in the Hoop area and two in the Snøhvit area.

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 2012 for our major development projects on the NCS.

Project	Operator	Statoil's share at 31 December 2012	Production start	Statoil equity capacity (mboe per day)
Aasta Hansteen	Statoil	75.00%	2017	100
Gudrun	Statoil	75.00%	2014	65
Valemon	Statoil	53.78%	2014	50
Gina Krog (formerly Dagny)	Statoil	58.46%	2017	50
Ivar Aasen	Det Norske	50.00%	2016	40
Goliat	Eni	35.00%	2014	30

Aasta Hansteen (Statoil interest 75%) 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 will also serve as a hub for other potential discoveries in the area. The plan for development and operation (PDO) for the field was submitted to the Norwegian Ministry of Petroleum and Energy in January 2013. Expected production start-up is 2017.

The **Gudrun** (Statoil interest 75%) oil and gas field is located in the North Sea. Production is scheduled to start in 2014. The total investments are estimated to amount to NOK 18.2 billion. The field will be developed with 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*. A total of seven production wells will be drilled and completed prior to production start-up.

Valemon, which is located in the North Sea, is being developed with 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 20.5 billion, and production start-up is expected to take place during the fourth quarter of 2014. Statoil's ownership interest in Valemon is 53.78% after the transaction with Centrica Resources Norway.

Gina Krog (formerly Dagny) (Statoil interest 58.46%) is an oil and gas discovery in the North Sea some 30 km north of the Sleipner field. In December 2011, the licence partners approved Statoil's proposed concept solution for Gina Krog. 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 the rich gas will be further processed. The development concept also includes gas injection in order to maximise the recovery factor for the field. The development concept includes a total of 15 wells. The project was sanctioned in the fourth quarter of 2012.

Ivar Aasen is an oil and gas field located in the Utsira High Area. It will be developed with 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 oilfield to be developed in the Barents Sea. The field is being developed with subsea wells tied back to a circular FPSO vessel. The oil will be offloaded to shuttle tankers. The Goliat development is operated by Eni, and Statoil holds an interest of 35%. The operator expects production start-up in the third quarter of 2014. The operator has estimated the development costs for the field to be NOK 36.7 billion.

Fast-track projects are all relatively small projects, yielding high returns. The 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 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 2012, ten projects have been sanctioned and are currently in the execution phase, while several other fast-track candidates are being considered.

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. During 2012, Statoil set a very ambitious target of increasing the average recovery rate from our fields on the NCS from 50% to an estimated 60% by 2020.

There is a therefore high activity on 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, upgrading of the existing water injection system, and increased water injection capacity on Gullfaks B. The project is expected to be completed in 2013.

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 December 2013.

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 to be NOK 10.2 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 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.

The **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 PDO was approved on 27 March 2012. The investment cost for the project is estimated to be NOK 16.5 billion and completion of the development is currently expected to take place in 2015.

The **Gullfaks subsea compression project** is the second large subsea gas compression project planned by Statoil on the NCS. Subsea gas compression will have a great effect on the Gullfaks field. With the help of this subsea technology, combined with conventional low-pressure production, the recovery rate from the Gullfaks South Brent reservoir can be increased from 62% to 74%. The project is scheduled for completion in 2015.

3.5.5 Decommissioning on the NCS

Statoil completed the first shutdown and removal project on the NCS in 2012.

The Norwegian government has laid down strict procedures for the removal and disposal of offshore oil and gas installations under the Convention for the Protection of the Marine Environment of the Northeast Atlantic (the OSPAR Convention).

In 2012, Statoil completed the Troll Oseberg Gas Injection (TOGI) cessation project, the first shutdown and removal project on the NCS.

In 2013, Statoil will carry out shutdown of the Glitne field. The decommissioning of the field is expected to be completed in the period 2013-2015. (For further details regarding the Glitne field, see the section *Business overview - Development and Production Norway - Fields in production on the NCS - Operations North Sea West).*

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 most of Statoil's future production growth.

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

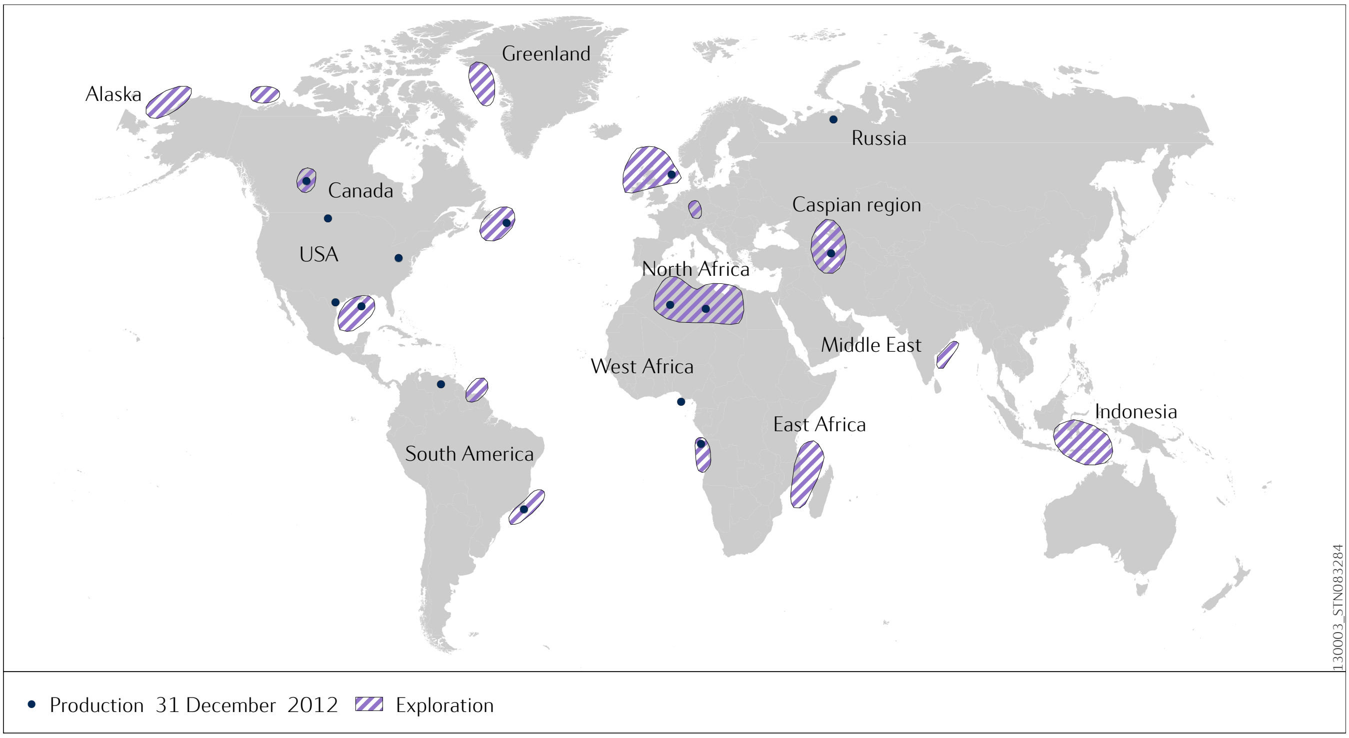
On 16 January 2013, Statoil, together with partners BP and Sonatrach, was hit by a terrorist attack at the In Amenas gas production facility in Algeria. Five Statoil colleagues lost their lives in the attack. Statoil has initiated an investigation to determine the relevant chain of events before, during and after the attack in order to provide the company with a basis for making further improvements to its security, risk assessment and emergency preparedness.

In 2012, 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 2012, DPI produced 33% of Statoil's total equity production of oil and gas. Statoil has in 2012 been engaged in cost recovery in connection with previous investments in Iran, and some of this is reported as production. Statoil still maintains an office in Teheran that addresses the closing of employment benefit issues and payment of remaining taxes related to previous investments.

As of 31 December 2012, 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), North Africa (Libya), and Europe and Asia (Azerbaijan, the Faroe Islands, Germany, Greenland, India, Indonesia, and the UK). The Iran licences have expired. Statoil also has representative offices in Kazakhstan, Mexico, Turkmenistan, and the United Arab Emirates.

The main sanctioned development projects in which DPI is involved are in Angola, Canada, the UK, and the US. We are well positioned for further growth through a substantial pre-sanctioned project portfolio, including a strengthened US onshore position as a result of the acquisition of 69,933 operated net acres in Marcellus in December 2012, where Statoil will become the operator, and the Eagle Ford operatorship, which will start in 2013.

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



Key events and portfolio developments in 2012:

- Equity production increased by 25% from 2011, to 669 mboe per day in 2012:
  - Gulf of Mexico field Caesar Tonga started production on 7 March 2012.
  - The Kizomba Satellites Phase 1 in Angola started production on 18 May.
  - PSVM in Angola started production on 6 December.

- In May 2012, Statoil's exit from the West Qurna 2 project in Iraq was formally approved by the Iraqi authorities.
- We signed a cooperation agreement with Rosneft in May 2012 to jointly explore offshore frontier areas off Russia and Norway and to conduct joint technical studies on two onshore Russian assets. Several agreements detailing the cooperation have since been signed and work is ongoing to complete the remaining agreements.
- The frame agreement for Shtokman (Russia) expired on 30 June 2012.
- On 2 August 2012, Statoil divested the Front Runner and Thunder Hawk producing fields in the Gulf of Mexico.
- We made the final investment decision to go ahead with the UK Mariner field in December 2012.
- We strengthened our portfolio through significant discoveries off the coasts of Tanzania and Brazil, confirming the potential of previous significant offshore discoveries off Brazil.
- We were awarded seven exploration licences on the UK continental shelf in 2012. Statoil will be the operator for two of the licences and our working interest varies from 20% to 60%.
- We were the high bidder on 26 leases in the 2012 Gulf of Mexico lease sale. With the additions, we will control more than 340 leases in the Gulf of Mexico.
- In December 2012, we acquired 25% in the BM-ES-22A licence in Brazil through an agreement with Vale SA. The acquisition is pending government approval and other conditions.
- We acquired 69,933 operated net acres in Marcellus on 18 December 2012.
- We and our partners sanctioned the Hebron field located in East Coast Canada in December 2012.

3.6.2 International production

Statoil's entitlement production outside Norway was about 26% of Statoil's total entitlement production in 2012.

The following table shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2012, 2011 and 2010. Entitlement production figures are after deductions for royalties paid in kind, production sharing and profit sharing.

Entitlement production	For the year ended 31 December 2012	2011	2010
Oil and NGL (mboe per day)	342	252	263
Natural gas (mmcm per day)	20	13	11
Total (mboe per day)	470	334	332

The table below provides information about the fields that contributed to production in 2012.

Field	Statoil's equity interest in %[1]	Operator	On stream	Licence expiry date	Average daily equity production in 2012 mboe/day	Average daily entitlement production in 2012 mboe/day
North America						
Canada: Hibernia	5.00	HMDC	1997	2027	6.8	6.8
Canada: Terra Nova	15.00	Suncor	2002	2022	3.5	3.5
Canada: Leismer Demo	60.00	Statoil	2010	HBP[2]	9.8	9.8
USA: Lorien	30.00	Noble	2006	Sold 2012	0.1	0.1
USA: Front Runner	25.00	Murphy Oil	2004	Sold 2012	1.7	1.7
USA: Spiderman Gas	18.33	Anadarko	2007	HBP	4.3	4.3
USA: Zia	35.00	Devon	2003	HBP	0.1	0.1
USA: Marcellus shale gas[3]	Varies	Chesapeake/Statoil	2008	HBP	61.5	61.5
USA: Eagle Ford shale gas[3]	Varies	Talisman	2010	HBP	14.4	14.4
USA: Tahiti	25.00	Chevron	2009	HBP	23.4	23.4
USA: Thunder Hawk	25.00	Murphy Oil	2009	Sold 2012	0.8	0.8
USA: Bakken[3]	Varies	Statoil/others	2011	HBP	36.3	36.3
USA: Caesar Tonga	23.55	Anadarko	2012	HBP	8.7	8.7
Total North America					171.4	171.4
South America and sub-Saharan Africa						
Brazil: Peregrino	60.00	Statoil	2011	2034	36.8	36.8
Venezuela: Petrocedeño[4]	9.68	Petrocedeño	2008	2032	12.3	12.3
Angola: Girassol/Jasmim	23.33	Total	2001	2022	28.9	9.1
Angola: Dalia	23.33	Total	2006	2024	52.1	15.3
Angola: Rosa	23.33	Total	2007	2027	15.7	5.8
Angola: Pazflor	23.33	Total	2011	2030	45.0	39.9
Angola: Kizomba A	13.33	ExxonMobil	2004	2026	14.8	4.7
Angola: Kizomba B	13.33	ExxonMobil	2005	2027	15.3	4.7
Angola: Kizomba Satellites phase 1	13.33	ExxonMobil	2012	2032	4.9	4.4
Angola: Marimba	13.33	ExxonMobil	2007	2027	2.3	0.5
Angola: Mondo	13.33	ExxonMobil	2008	2029	7.7	0.8
Angola: Saxi-Batuque	13.33	ExxonMobil	2008	2029	9.2	2.6
Angola: PSVM	13.33	BP	2012	2031	0.7	0.6
Angola: Block 4/05	20.00	Sonangol P&P	2009	2026	2.6	2.4
Nigeria: Agbami	20.21	Chevron	2008	2024	47.0	40.4
Total South America and sub-Saharan Africa					295.3	180.5
Middle East and North Africa						
Algeria: In Salah	31.85	Sonatrach/BP/Statoil	2004	2027	44.7	20.2
Algeria: In Amenas	45.90	Sonatrach/BP/Statoil	2006	2022	21.8	12.1
Iran: South Pars	37.00	POGC	2008	2012	4.1	4.1
Libya: Mabruk	12.50	Total	1995	2028	3.3	3.0
Libya: Murzuq	10.00	Repsol	2003	2032	9.9	5.7
Total Middle East and North Africa					83.8	45.0
Europe and Asia						
Azerbaijan: ACG	8.56	BP	1997	2024	56.9	20.1
Azerbaijan: Shah Deniz	25.50	BP	2006	2031	45.1	40.8
Russia: Kharyaga	30.00	Total	1999	2032	9.6	5.5
UK: Alba	17.00	Chevron	1994	2018	3.8	3.8
UK: Jupiter	30.00	ConocoPhillips	1995	2013	0.2	0.2
UK: Schiehallion	5.88	BP	1998	2017	2.6	2.6
Total Europe and Asia					118.2	72.9
Total Development and Production International (DPI)					668.7	469.8

(1) Equity interest as of 31 December 2012.

(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 continuing 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.

The table below provides information about production per country in 2012.

Country	Average daily equity production mboe/day	Average daily entitlement production mboe/day
North America	171.4	171.4
Canada	20.1	20.1
USA	151.3	151.3
South America and sub-Saharan Africa	283.0	168.1
Brazil	36.8	36.8
Angola	199.2	90.9
Nigeria	47.0	40.4
Middle East and North Africa	83.8	45.0
Algeria	66.5	32.3
Iran	4.1	4.1
Libya	13.3	8.7
Europe and Asia	118.2	72.9
Azerbaijan	102.0	60.8
Russia	9.6	5.5
UK	6.6	6.6
Total Development and Production International (DPI)	656	457
Equity accounted production		
Venezuela: Petrocedeño	12.3	12.3
Total Development and Production International (DPI) including share of equity accounted production	669	470

The following sections provide information about the main producing assets internationally. See section 4 *Financial review* for a discussion of the results of operations for 2012, 2011 and 2010.

3.6.2.1 North America

Production in North America comprises Canada and the USA. The Bakken shale investment became a key contributor to our portfolio in 2012, while in March, the Gulf of Mexico saw the start-up of Caesar Tonga, one of a number of key development projects.

Canada

In 2007, we acquired 100% of the shares in North American Oil Sands Corporation and operatorship of 1,129 square kilometres (279,053 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** is the first phase of the KKD development. It has been operational since early 2011. The project achieved peak production of 20 mboe per day in 2012, and production ramp-up and operational performance have been successful.

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 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 756,363 acres (including 69,933 net acres acquired in 2012) at the end of 2012. The closing date for the 2012 transactions was 18 December 2012 (with 1 September 2012 as the effective date), on which date Statoil became the operator of record for the assets. In order to ensure an orderly transfer of tasks from the sellers to Statoil, transition services agreements (TSAs) have been established.

Marcellus provides Statoil with a long-life gas asset with considerable optionality in relation to the timing of drilling and production from these leases.

Statoil entered the **Eagle Ford** shale formation (located in south west Texas) in 2010. Through agreements with Enduring Resources LLC and Talisman Energy Inc., Statoil acquired 67,000 net acres. In 2013, Statoil will become operator for 50% of the Eagle Ford acreage, in line with the agreement with Talisman Energy Inc. from 2010. The transfer of operatorship will be conducted in phases in order to maintain high HSE standards, and operational and business continuity. This process will commence in the first quarter of 2013 and will be finalised by the end of 2013. Statoil's net acreage position at the end of 2012 was 73,124 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 at the end of 2012 was 347,164 acres.

The **Tahiti** oilfield (Statoil interest 25%) is operated by Chevron. The field is located in the Green Canyon area of the deepwater Gulf of Mexico. It consists of seven wells in three locations connected to a floating facility.

The **Caesar Tonga** oilfield (Statoil interest 23.6%) is operated by Anadarko Petroleum. The field is located in the Green Canyon area. It consists of three wells tied back to the Anadarko-operated Constitution spar host. The field started production on 7 March 2012.

3.6.2.2 South America and sub-Saharan Africa

Production activities in South America and sub-Saharan Africa comprise the Peregrino operatorship in Brazil, the Petrocedenõ project in Venezuela, the Agbami project in Nigeria, and four Angolan offshore blocks.

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 well head platforms with drilling capability and it is processed on the Peregrino FPSO. Statoil holds a 60% ownership interest in the field and is the operator.

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.

The Petrocedeño plant is still operating below design capacity. A recovery programme is ongoing to improve the situation.

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

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

Block 15 has production from the **Kizomba A, Kizomba B, Kizomba C-Mondo** and **Kizomba C-Saxi Batuque** FPSOs. In addition, one satellite, **Marimba**, is producing through a subsea tie-back to the Kizomba A FPSO. In 2012, the **Kizomba Satellites phase 1**, consisting of the Clochas and Mavacola discoveries, came into production, producing both over the Kizomba A and the Kizomba B FPSO. Block 15 is operated by Esso Angola, a subsidiary of ExxonMobil, and Statoil holds a 13.3% interest in Block 15.

Block 4/05 includes the **Gimboa** field, which is produced over the Gimboa FPSO. Sonangol P&P is the operator for block 4/05 and Statoil holds a 20% interest.

Block 31 came into production in December 2012 with the start-up of 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 is still debating the Petroleum Industry Bill (PIB), which will most likely increase the government take if passed. Timing and outcome are uncertain.

Together with our partner Chevron, we have initiated arbitration with the national oil company NNPC concerning the interpretation of certain clauses in the production-sharing contract (PSC) that governs our share of Agbami.

3.6.2.3 Middle East and North Africa

Statoil's production in the Middle East and North Africa in 2012 took place in Algeria and Libya.

Algeria
The **In Salah** onshore gas development in which Statoil has a 31.9% interest is Algeria's third-largest gas development. The field is currently producing at plateau level of around 130 mboe per day.

A contract of association, including mechanisms for revenue sharing, governs the rights and obligations of the joint operatorship between Sonatrach, BP and Statoil.

In the In Salah Gas Compression Project, gas compression facilities were installed on the three existing northern fields in 2010 in order to maintain production rates from the fields.

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%.

On 16 January 2013, Statoil, together with partners BP and Sonatrach, were hit by a terrorist attack at the In Amenas gas production facility. Five Statoil colleagues lost their lives in the attack. Statoil has initiated an investigation to determine the relevant chain of events before, during and after the attack in order to provide the company with a basis for making further improvements to its security, risk assessment and emergency preparedness.

On 22 February, limited production from the plant recommenced, but the effect of the attack on production in 2013 remains uncertain. Statoil will not return personnel until the necessary security conditions have been established.

Libya
In February 2011, following the Libyan civil war, Statoil's Libyan operations were suspended and Statoil's offices in Tripoli were temporarily closed. Statoil's office in Tripoli was reopened on 20 March 2012.

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. Murzuq resumed production in November 2011. 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. Mabruk resumed production in January 2012.

3.6.2.4 Europe and Asia

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)** oilfield and a 25.5% share in the **Shah Deniz** gas and condensate field. BP is the operator for both fields. Statoil has an 8.7% stake in the 1,760-km Baku-Tbilisi-Ceyhan (BTC) 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 has been established to manage gas allocation and sales to customers in Azerbaijan, Georgia and Turkey.

Russia
Statoil has a 30% share in the **Kharyaga** oilfield 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 three production licences. The **Alba** oilfield (Statoil interest 17%) is located in the central part of the UK North Sea and is operated by Chevron. The **Schiehallion** oilfield (Statoil interest 5.9%) is located west of the Shetland Islands and is operated by BP. **Jupiter** (Statoil interest 30%) is a gas field located in the southern part of the UK North Sea, and ConocoPhillips is the operator of the field.

3.6.3 International exploration

Statoil has significant international exploration activity, and the company was involved in 27 wells that were completed in 2012.

Statoil has significant international exploration activity, and we were involved in 27 wells that were completed in 2012 (including both Statoil-operated and partner-operated activity). Nine wells (exploration and appraisal) were announced as discoveries in the period, including the Pão de Açúcar discovery (operated by Repsol), and the Zafarani and Lavani (Statoil-operated) discoveries in Tanzania. A total of 12 wells were reported dry, while six wells were under evaluation at year end.

Statoil signed a cooperation agreement with Rosneft in May 2012 to jointly explore offshore frontier areas in Russia and Norway and to conduct joint technical studies on two onshore Russian assets. The offshore licences are Perseevsky (located in the Russian part of the Central Barents Sea) and Kashevarovsky, Lisyansky and Magadan-1 (all in the Sea of Okhotsk). The onshore licences are North-Komsomolskoye (West Siberia) and Stavropol (Stavropol region). Several agreements detailing the cooperation have since been signed, and work is ongoing to conclude the remaining agreements.

The table below shows the exploratory wells drilled internationally in the last three years. The lifting of the Gulf of Mexico moratorium and increased activity in several countries, particularly Indonesia and Tanzania, have led to the completion of more international wells than in previous years.

		2012	2011	2010
North America	-Statoil operated	3	2	0
	-Partner operated	6	4	5
South America/sub-saharan Africa	-Statoil operated	5	3	0
	-Partner operated	7	4	10
Middle East and North-Africa	-Statoil operated	0	1	0
	-Partner operated	1	0	2
Europe and Asia	-Statoil operated	3	0	0
	-Partner operated	2	2	1
	Totals	27	16	18

The regions where Statoil had exploration activity in 2012 are presented below.

North America

USA
Statoil has significant activities in the USA, with approximately 340 (as of 31 December 2012) exploration leases in the Gulf of Mexico (GoM) and 66 in Alaska - about 19,500 and 1,500 square kilometres respectively. The group was successful in the Department of the Interior's GoM Central Region lease sale, winning 26 leases in 2012.

Statoil was among the most active explorers in the GoM in 2012, serving as the operator for three completed wells: Kilchurn and the Kilchurn sidetrack, which are under evaluation, and Bioko (dry). In addition, the group was involved in three partner-operated wildcat wells and three appraisal wells. In 2012, Statoil's exploration activities in the GoM have returned to a level similar to that prior to the Macondo incident.

Canada
Off the coast of Canada, Statoil is operator and partner in 12 exploration licences (ELs), including both off the coast of Newfoundland and in the Beaufort Sea. Statoil is also operator for four significant discovery licences (SDLs) off the coast of Newfoundland.

In 2012, Statoil was awarded two licences in the Flemish Pass basin and entered the Orphan basin as a partner in line with its early access at scale strategy. Statoil also entered the Beaufort Sea as part of the group's overall move into Arctic exploration. In 2012, Statoil and partners Chevron Canada and Repsol E&P Canada acquired 3D seismic data in preparation for future drilling activities.

South America and sub-Saharan Africa

Angola

Statoil has interests in five blocks in the Congo basin and five blocks in the Kwanza basin (pre-salt licences), with participating interests varying from 5% to 55%. Acquisition of a 26,000-square-kilometre 3D survey in the Kwanza basin (covering Blocks 24, 25, 38, 39 and 40) started on 1 January 2012. The priority area in Block 39 was completed in June and fast-track products were delivered in December of the same year, while acquisition of a larger area continued until January 2013.

Brazil

Statoil holds acreage in the Campos basin and in the frontier Espírito Santo, Jequitinhonha and Camamu-Almada basins. In December, Statoil acquired 25% of the BM-ES-22A licence in Brazil through an agreement with Vale SA. The transaction is subject to approval by Brazilian authorities and other conditions prior to closing.

Two wells were announced as discoveries in 2012: the Pão de Açúcar discovery (operated by Repsol) and the Peregrino South appraisal discovery (Statoil-operated) in Brazil.

Tanzania

Statoil operates Block 2 and holds a 65% working interest. Two exploration wells have been drilled in 2012, proving significant volumes of gas in the Zafarani and Lavani prospects. Moreover, a successful appraisal well on Lavani was announced in 2012. In March 2013 the Tangawizi exploration well was announced as discovery, proving further significant gas volumes. More prospects in the block will be tested in 2013.

Ghana

Statoil acquired first acreage in Ghana by taking a 35% share in a deepwater licence operated by Hess. The driver for Statoil entering this licence was to test a new play. Hydrocarbons were found in a proven play, but the discovery was considered too small to compete with other ongoing projects. Statoil has divested its share in this block.

Mozambique

In 2012, Statoil farmed down a 25% working interest in its exploration licence off the coast of Mozambique in the Rovuma basin. Statoil operates the licence and retains a 65% working interest after the farm down. The licence covers 7,800 square kilometres with a water depth that varies between 300 and 2,400 metres. The partnership is now preparing to spud the first well.

Suriname

Statoil has a 30% share in Block 47 in a frontier area in the Guyana Basin. The acquisition of 3,000 square kilometres of 3D seismic was finalised in September 2012.

Middle East and North Africa

Statoil has exploration licences in **Libya**, but there was no activity in 2012 due to the unrest in the country. We participated in one appraisal well on the Hassi Farida discovery in **Algeria**.

Europe and Asia (excluding Norway)

UK

Statoil was awarded seven exploration licences on the UK continental shelf in 2012. We have committed to drilling three wells in one licence and to acquiring or reprocessing seismic in the other licences. Statoil will be the operator for two of the licences and our working interest varies from 20% to 60%. The licences are situated in the Catcher area on the Western Platform and in the Faroe-Shetland basin.

Faroe Islands

Statoil operates five licences in the Faroe Islands, with working interests ranging from 40% to 50%. Drilling of the Brugdan II well started in 2012, but it was decided to temporarily suspend drilling operations due to the expected bad weather in the winter season. Drilling will resume at a later stage. We also acquired 3D seismic data for two licences in 2012. L010 expired at the beginning of March 2013.

Greenland

Statoil is a partner in three licences off the coast of West Greenland, with interests ranging from 15% to 31%; 3D seismic data was acquired in Blocks 5 and 8 in 2012. All commitments in the current exploration period have been fulfilled.

Indonesia

Statoil has interests in eight production-sharing contract (PSC) licences in Indonesia. Our working interests in the licences vary from 19% to 80%, and we operate Halmahera II. Our working interest in the Aru PSC was acquired in 2012, and we committed to acquiring 3D seismic data. The Karama licence has been relinquished.

Germany
Statoil entered the Rhein and Ruhr licences through a farm-in agreement with Wintershall in 2012. Statoil has a 49% interest in the licences. The licences target unconventional gas exploration and the commitments are to drill four shallow wells in addition to shooting 300 kilometres of 2D seismic.

3.6.4 Fields under development internationally

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

This section covers projects under development. Significant pre-sanctioned projects, including some discoveries in the early evaluation phase, are also presented.

Sanctioned projects coming on stream 2013-2014 *	Statoil's share at 31 December 2012	Operator	Time of sanctioning	Production start
Azerbaijan: Chiraq oil project	8.56%	BP	2010	2013
Algeria: In Salah Southern Fields	31.85%	Sonatrach/BP/Statoil	2010	2014
Angola: CLOV	23.33%	Total	2010	2014
USA: Big Foot	27.50%	Chevron	2010	2014
USA: Jack	25.00%	Chevron	2010	2014
USA: St. Malo	21.50%	Chevron	2010	2014
Canada: Hibernia South Extension	10.50%	Exxon Mobil	2011	2014

* Not exhaustive

3.6.4.1 North America

Statoil has significant ongoing development projects in North America.

Caesar Tonga (Statoil interest 23.6%) in the US, operated by Anadarko Petroleum, is expected to add one producing well with a tie back to the Anadarko-operated Constitution Spar host in the second quarter of 2013.

Tahiti Phase 2 (Statoil interest 25%) in the US, operated by Chevron, will add two producing and three water-injection wells. Injection from the first two water-injection wells started in the first quarter 2012, while first oil from two additional producers is expected in the second half of 2013.

Statoil has a 25% working interest in the **Jack** oilfield and a 21.5% working interest in **St. Malo,** 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 in 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 scheduled for mid-2014.

Discovered in 2007, **Julia** (Statoil interest 50%) is one of the major discoveries in the Paleogene, with a significant in-place volume. After judicial proceedings and a settlement, a Suspension of Production was issued for the Julia Unit by the Bureau of Safety and Environmental Enforcement (BSEE) in January 2012. The operator ExxonMobil has restarted the project and is making progress in accordance with the agreed schedule. First oil is expected by mid-2016.

In **Canada**, Statoil has a 60% interest and is the operator of the KKD Oil Sands Partnership. Statoil is maturing the **Corner** and **Leismer Expansion** projects to the concept selection phase. The first phase, the Leismer Demonstration Project, came on stream in early 2011.

Statoil has a 10.5% interest in the Exxon-operated **Hibernia South Extension** (a satellite of Hibernia) and all wells are expected to be online in 2014.

On Canada's east coast, 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. The Hebron partners sanctioned the project in 2012. First oil is expected in 2017.

3.6.4.2 South America and sub-Saharan Africa

In 2012, South America and sub-Saharan Africa had several ongoing field development projects in 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 over 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** consists of the discoveries Bavuka, Kakocha, and Mondo South. All major development contracts for the Kizomba Satellites Phase 2 Project have been approved by the contracting group and Sonangol, and the project is progressing according to plan. First oil is scheduled for 2016. 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,** development of the discoveries that was approved in 2012, Sangos, N'Goma and Cinguvu, is currently ongoing. Block 15/06 is operated by Eni, and Statoil's interest is 5%.

3.6.4.3 Middle East and North Africa

In 2012, Statoil's field development in the Middle East and North Africa was focused on Algeria, and we left the West Qurna 2 project in Iraq.

The **In Salah Southern Field Development Project** in Algeria was sanctioned in late 2010. In January 2011, Statoil announced that the development plan was approved. This project will mature the remaining four discoveries into production and it is scheduled to come on stream in 2014. 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.

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 2014. This will make it possible to reduce well head pressure and maintain the contractual production commitment.

The In Amenas facilities are operated through a joint operatorship between Sonatrach, BP and Statoil.

The **Hassi Mouina** exploration phase was extended until September 2012. We still aim to develop the field, but need to reach agreement with the Algerian authorities on technical and commercial terms.

In May 2012, Statoil's exit from the **West Qurna 2** project in Iraq was formally approved by the Iraqi authorities. Statoil's 18.75% share was subsequently transferred to Lukoil. Statoil became a partner in this project after a technical service agreement was signed with the Iraqi authorities in early 2010.

3.6.4.4 Europe and Asia

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

Azerbaijan
The **Chirag** Oil Project, the sixth platform on the ACG oilfield, was sanctioned by the ACG partnership in 2010. It has a design capacity of 185 mboe per day. BP is the operator for this project. First production from this project is scheduled for late 2013.

The concept for the **Shah Deniz Stage 2 field development** was agreed by the partners in late 2010. Project development operator BP estimates annual production from Shah Deniz Stage 2 to be 16 bcm of gas per year and about 100 mboe per day of condensate. The current plan is to make a final investment decision in 2013. That would mean first gas from the Shah Deniz Stage 2 in 2018.

United Kingdom
Statoil is the operator for the **Mariner** heavy oil project and has a 65.1% interest. In December 2012, Statoil made the investment decision to develop the Mariner oilfield development. 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 the subsea tie-in of **Mariner East,** a small heavy oil discovery. We are the operator and increased our equity to 92% in June 2012 through an equity swap with OMV.

Statoil is the operator for and holds an 81.6% interest in **Bressay**. Bressay is also a heavy oil discovery for which concept selection was approved in March 2013.

Rosebank is a heavy oil project operated by Chevron. In 2012, the partners reached concept selection, an FPSO. Statoil has a 30% share in this project.

Ireland

Statoil has a 36.5% interest in the **Corrib** gas field operated by Shell, which is under development. According to the operator, outstanding work at the onshore processing terminal will be completed by summer 2013. Commissioning is planned for 2014. First gas from Corrib will depend on the duration of the tunnelling work and/or the timing of permits required for the operation of the field.

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. We are also responsible for developing a profitable renewable energy position.

In 2012, we sold 41.3 billion cubic metres (bcm) of natural gas from the Norwegian continental shelf (NCS) on our own behalf, in addition to approximately 39.9 bcm of NCS gas on behalf of the Norwegian State. Statoil's total European gas sales, including third-party gas, amounted to 87.5 bcm in 2012, 43.2 bcm of which was gas sold on behalf of the Norwegian State. That makes us the second-largest gas supplier to Europe. The largest supplier is Gazprom.

In 2012, we also sold 714 million barrels of crude oil and condensate, approximately 15 million tonnes of refined oil products from our own refineries, and 14 million tonnes of natural gas liquids (NGL). Tjeldbergodden produced approximately 807,000 tonnes of methanol. Our international trading activities make us one of the world's largest net crude oil sellers.

In 2012, the gas market was characterised by high market prices and good customer off-take. Refinery margins and trading margins were higher than in 2011. The operation of facilities has been stable, and HSE results are within our target for the year.

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

Key events in 2012:
- Statoil started transporting Bakken crude from North Dakota in the US to the market by rail.
- Statoil and Wintershall entered into a 10-year gas sales agreement for the delivery of a total of 45 billion cubic metres (bcm) to the German and other north west European markets.
- The Sheringham Shoal offshore wind farm (owned equally by Statoil and Statkraft through the joint venture company Scira Offshore Energy Limited) was officially opened.
- Together with Statkraft, we acquired the Dudgeon offshore wind farm project (off the UK coast) through the acquisition of all the shares in Dudgeon Offshore Wind Limited. Statoil will hold a 70% share in the company

3.7.2 Natural Gas

The natural gas (NG) business cluster 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 (Houston and 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 us access to customers throughout Europe.

By the end of 2012, Statoil had a 5% ownership interest in the Gassled transportation system.

3.7.2.1 Gas sales and marketing

We transport and market approximately 70% of all NCS gas and have a growing US gas position. In Europe, the gas is sold through long-term contracts with major European utilities, and a growing proportion is sold directly and on traded markets.

The direct sales take place 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 US, gas is sold through a mix of contracts and trading in 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.

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. As a result of recent ongoing gas market developments in many regions in Europe, Statoil has used the price reviews to agree structural solutions for the long term with several of its customers. Key characteristics are a gradual transition from oil indexation towards gas hub-related pricing, as well as a reduction in some volume commitments and of the buyers' daily and annual flexibility.

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 in 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. Most of the gas is sold through long-term contracts. Our main customers are large national or regional gas companies such as E.ON Ruhrgas, GdF Suez, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), RWE and GasTerra. We are also growing our marketing of gas to large industrial customers, power producers and wholesalers in addition to spot market sales.

Our group-wide 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 are also increasing our activity in continental marketplaces in France, the Netherlands, Belgium and Germany.

Statoil has end-user sales business based in Belgium and the UK, serving major customers in Belgium, the UK, the Netherlands, Germany and France.

Statoil UK holds a one-third stake in Aldbrough Gas Storage, operated by SSE Hornsea Ltd. During 2012 all nine caverns came into full commercial operation.

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

SNG has two 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. The long-term capacity agreement was renegotiated in December 2010 and, as a consequence, Statoil's commitments relating to the re-gasification capacity at Cove Point (CPX) have been significantly reduced. Through Statoil, SDFI pays for a share of the capacity at the Cove Point re-gasification terminal, downstream pipeline capacity and storage capacity.

LNG is sourced from the Snøhvit LNG facility in Norway and from third-party suppliers. Market demand for LNG has shown a weaker trend since June 2012, compared to the first half of 2012. However, the latest market signals indicate a positive upward trend. Due to continued low prices in the US, no LNG cargoes have been delivered to the US. Statoil's LNG cargoes have been diverted away from the US market into higher-priced markets in Europe, South America and Asia.

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

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

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 2 billion cubic metres (bcm) per year, approximately 200,000 mcf/day, enabling Statoil to transport gas from the Northern Marcellus production area to Manhattan, NY, with an expected in-service date in late 2013.

SNG has entered into a gas transportation agreement with National Fuel Gas Supply Corporation for a total capacity of 3.2 billion cubic metres (bcm) per year, approximately 320,000 mcf/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.

Azerbaijan

Statoil has an ownership interest 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.

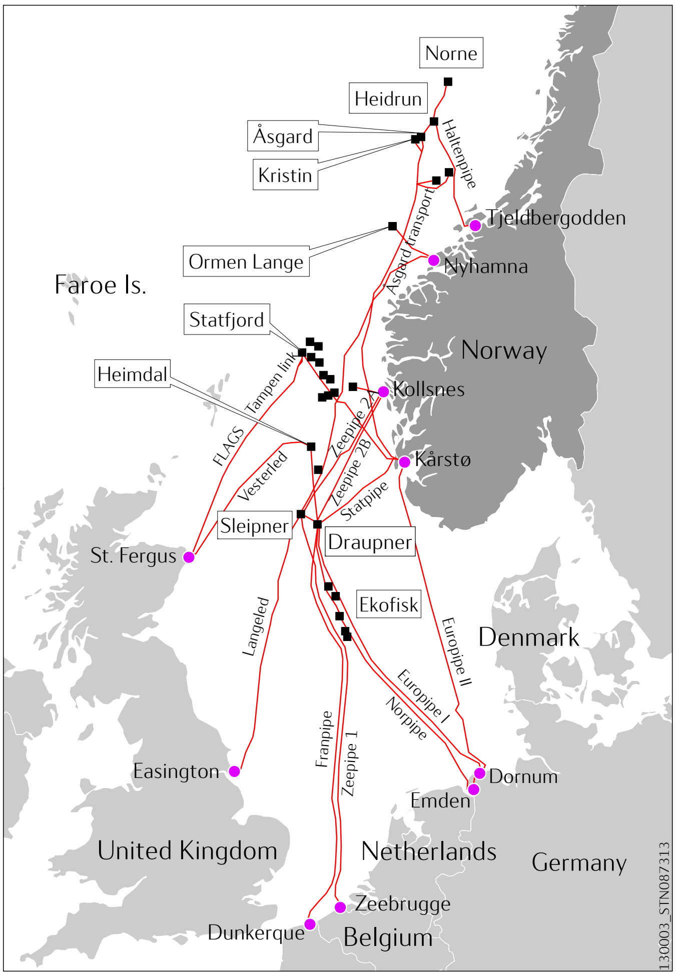
For the stage 2 development of Shah Deniz, the current plan is to make a final investment decision in 2013. In June 2012, the governments of Turkey and Azerbaijan signed an inter-governmental agreement relating to the development of an independent pipeline for the transit of gas across Turkey. During 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 towards Baumgarten, Austria. Together with key partners in Shah Deniz, Statoil is preparing to resume negotiations with potential buyers in Europe in order to be able to conclude the sale of gas from Shah Deniz stage 2 and the pipeline route to Europe by mid-2013.

Algeria

Statoil has ownership interests in the In Salah and In Amenas gas fields, Algeria's third-largest and fourth-largest gas developments, respectively. All of the gas produced 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 the ownership interest is now 5.0%. The divestment did not affect Statoil's position as 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 infrastructure.

3.7.2.3 Processing

Statoil is the technical service 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 responsible technical service 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 intended to receive gas from the Troll field only. Kollsnes now also receives gas from the Visund, Kvitebjørn and Fram fields. These volumes are processed through the NGL plant.

Kårstø gas processing plant
Statoil is the responsible TSP 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 stabilised condensate. When all of these products have been separated from the rich gas, the remaining dry gas is sent to customers through the Gassled pipeline network to receiving terminals in Europe.

The Kårstø processing plant has been undergoing comprehensive upgrading in order to meet safety and technical requirements, and future needs. The Kårstø Expansion Project (KEP) is intended to make the Kårstø facilities more robust and ensure safe and efficient operation. The total project investment is estimated to be approximately NOK 6 billion. It is expected to be completed in 2013.

3.7.3 Crude oil, liquids and products

The crude oil, liquids and products (CLP) business cluster adds value through the processing and 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 tight oil.

In 2012, CLP sold 714 million barrels of crude oil and condensate, approximately 15 million tonnes of refined oil products from our own refineries and 14 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, operating from sales offices in Stavanger, Oslo, London, Singapore, Stamford and Calgary and marketing and trading 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 2012, MPR sold 714 million barrels of crude and condensate, including supplies to our own refineries, while NGL volumes were 171 million barrels. 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 in the spot market based on publicly quoted market prices. Of the total 714 million barrels sold in 2012, approximately 38% were Statoil's own equity volumes. Of the total 171 million barrels of NGL sold in 2012, approximately 39% were Statoil's own 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 Condensate and LPG volumes from Melkøya. CLP also lifts equity LPG and condensate from Algeria.

In addition, we market equity crude oil, condensate and NGL production from Statoil's unconventional assets in North America. They include Alberta oil sands, Bakken, Eagle Ford, and Marcellus. Unconventional volumes were mostly sold in the spot market based on publicly quoted prices.

Marketing activities are also optimised through lease contracts and long-term agreements for the utilisation of third-party assets.

3.7.3.2 Processing and transportation

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. We also expect the blending facilities and full terminal capacity to strengthen our marketing and trading positions in the North American market. The terminal is an integral part of our marketing of equity volumes of heavy oil.

Mongstad terminal
Statoil operates the Mongstad terminal, which has storage capacity of 9.4 million barrels of crude oil. Statoil has an ownership interest of 65%, while Petoro has 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 transshipment 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 except for Snøhvit.

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 and, until 1 November 2012, it was responsible for the oil terminal at South Riding Point in the Bahamas.

In addition, we own 10% of production capacity at the Shell-operated refinery in Pernis in the Netherlands, which has a crude oil distillation capacity of 400,000 barrels per day.

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, until 1 November 2012, it was TSP for the oil terminal at South Riding Point, Bahamas. For further information about Kårstø, Kollsnes, Transport Net and South Riding Point, see the sections *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	2012	2011	2010	2012	2011	2010	2012	2011	2010	2012	2011	2010
Mongstad	**11.9**	11.3	9.9	**9.4**	9.3	8.7	**95.2**	98.4	97.3	**92.7**	89.9	82.7
Kalundborg	**4.9**	4.4	4.8	**5.4**	5.4	5.5	**94.4**	93.24	97.2	**88.8**	95.9	86.6
Tjeldbergodden	**0.81**	0.86	0.8	**0.95**	0.95	0.95	**86.4**	97.2	95.0	**97.5**	97.3	96.9

[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 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 a medium-sized, modern refinery. It 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 hydrocarbons.

The Mongstad refinery, which was built in 1975, was significantly expanded and upgraded in the late 1980s. It has been subject to considerable investment over the last 15 years in order to meet new product specifications and improved energy efficiency. A medium-sized, modern refinery, it 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, 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.

The CHP plant is 100% owned by Dong Generation Norge AS. It produces electric heat and power from gas received from Troll 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. The plant is operated by Dong Energy.

Together with the Norwegian government, Statoil is involved in several projects that aim to develop solutions for carbon capture and storage (CCS) at Mongstad. See the section *Business overview - Marketing, Processing and Renewable Energy - Renewable energy* for further information.

Mongstad product yields and feedstock	For the year ended 31 December 2012		2011		2010	
LPG	402	3%	378	3%	360	4%
Gasoline/naphtha	5,174	43%	4,829	43%	4,258	43%
Jet/kerosene	896	7%	783	7%	681	7%
Gasoil	4,445	37%	4,234	37%	3,539	36%
Fuel oil	224	2%	183	2%	231	2%
Coke/sulphur	171	2%	228	2%	174	2%
Fuel, flare & loss	639	6%	684	6%	620	6%
Total throughput [1]	11,951	100%	11,320	100%	9,863	100%
Troll, Heidrun (FOB crude oils)	6,385	53%	6,751	60%	4,516	46%
Other North Sea crude oils (CIF crude oil)	2,056	17%	1,777	16%	2,452	25%
Other crude oils	609	5%	274	2%		
Residue	1,185	10%	1,278	11%	1,523	15%
Other fuel and blendstock	1,716	15%	1,239	11%	1,372	14%
Total feedstock	11,951	100%	11,320	100%	9,863	100%

[1] Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnarounds in 2010).

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.

Kalundborg product yields and feedstock	For the year ended 31 December 2012		2011		2010	
LPG	74	1%	60	1%	80	2%
Gasoline/naphtha	1,511	31%	1,399	32%	1,461	31%
Jet/kerosene	(2)	0%	39	1%	141	3%
Gasoil	2,448	50%	1,980	46%	2,124	44%
Fuel oil	709	14%	683	16%	756	16%
Coke/sulphur	5	0%	6	0%	7	0%
Fuel, flare & loss	190	4%	177	4%	186	4%
Total throughput [(1)]	4,935	100%	4,344	100%	4,755	100%
Condensates: Ormen Lange, Snøhvit, Sleipner	750	15%	594	14%	754	16%
Other North Sea crude oils	3,036	62%	2,854	66%	3,492	73%
Other fuel and blendstocks	366	7%	280	6%	234	5%
Other crudes	782	16%	617	14%	275	6%
Total feedstocks	4,935	100%	4,344	100%	4,755	100%

(1) Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnaround in 2010).

The refinery's reliability (on-stream factor) was good in 2012 and on a par with its best years. The throughput in 2012 was lower due to a planned maintenance turnaround. The product yield from the refinery is well positioned in relation to the expected future structure of demand in the European market.

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% of 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 was formally opened in September 2012. The wind farm is now in full production with 88 turbines and an installed capacity of 317MW. It is owned jointly with Statkraft. The estimated annual production is 1.1 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 three years. The overall performance of Hywind has exceeded expectations. Projects have now been initiated to investigate the possibility of installing the Hywind test pilot scheme in both the US and the UK. 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 (new 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 received consent, and engineering studies are currently being undertaken to optimise the development concept. The development is expected to be slightly larger than Sheringham Shoal (production of 1.25 TWh, providing power for 250,000 households) and, pending a final investment decision, it could be fully operational in 2017.

Dogger Bank
Statoil was awarded a 25% share in the UK Third Round Dogger Bank concession in 2010 together with partners RWE, SSE and Statkraft. The joint venture ("Forewind") is currently undertaking environmental studies and preparing applications for consent for the first two projects (each 1.2 GW). These applications are expected to be submitted to the UK planning authorities in the first half of 2013. Production could start towards the end of the decade.

Full-scale carbon capture Mongstad (CCM)
The Norwegian government and Statoil are planning a full-scale post combustion carbon dioxide capture project in conjunction with the combined heat and power (CHP) station at Mongstad. At full capacity, the volume of captured carbon dioxide from the CHP plant is expected to be around 1.2 million tonnes annually.

The full-scale carbon capture plant is a mega-project due to its size, complexity and the uniqueness of the novel technology involved. Five vendors are currently participating in a process for qualification of their capture technology. Through the Mongstad project, Statoil is supporting the realisation of a complete value chain for carbon capture, transport and storage. A final investment decision for this project is planned in 2016.

3.8 Statoil Fuel & Retail

Statoil Fuel & Retail (SFR) is a road transportation fuel retailer with a presence in eight countries across Scandinavia and central and eastern Europe.

SFR was established in May 2010 as a separate legal entity within the Statoil group. In October 2010, Statoil ASA transferred all activities relating to the fuel and retail business to SFR. Following an initial public offering, the shares of SFR were listed on the Oslo Stock Exchange (Oslo Børs) in October 2010. Up until June 2012, Statoil ASA was the majority shareholder in SFR, holding 54% of the shares.

On 19 June 2012, Statoil ASA sold its remaining 54% shareholding in SFR to Alimentation Couche-Tard for a cash consideration of NOK 8.3 billion. Up until this transaction, SFR was fully consolidated in the Statoil group with a 46% non-controlling interest. Following the sale of SFR, the fuel and retail segment ceased to exist, but the fuel supply agreement between Statoil and SFR continues. Sales of fuel from the MPR segment to SFR are presented as external sales in the MPR segment as of 20 June 2012.

3.9 Other Group

The Other reporting segment includes activities in Global Strategy and Development (GSB); Technology, Projects and Drilling (TPD); and Corporate Staffs and Services.

3.9.1 Global Strategy and Business Development (GSB)

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

GSB sets the strategic direction for Statoil and identifies, develops and delivers opportunities for global growth. 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 mergers, acquisitions and divestments
- **Corporate strategy and analysis:** responsible for corporate strategy development processes, competitor intelligence, industry analysis and the running of Statoil's strategic advisory council
- **Business development execution**: responsible for business development project execution, technical evaluation and commercial analysis
- Until 1 December 2012, the **new ventures** unit in GSB was responsible for pursuing unconventional resource growth. It established new ventures in Australia, the United States and Germany. As a result of these efforts, the unit became involved in the maturation and drilling of exploration acreage and was consequently moved to a different business area responsible for exploration.

3.9.2 Technology, Projects and Drilling (TPD)

Technology, Projects and Drilling (TPD) is an internal function that is responsible for delivering projects and wells and providing global support on standards and procurement. TPD is also responsible for promoting Statoil as a technology company.

Research, development and innovation

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

Statoil's RDI portfolio was reorganised in August 2012. The new structure of Statoil's research unit is driven by our ambition to become a world-leading research organisation. 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 academia programme that addresses 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.

RDI expenditure was approximately NOK 2.1 billion, NOK 2.2 billion and NOK 2.8 billion for the years 2010, 2011 and 2012, respectively. Cooperation with external partners such as academic institutions, RDI institutes and suppliers is crucial in relation to technology.

Selected technology advances and important milestones in 2012:
- Significant increase in the Arctic research activities.
- Established a programme for unconventional resources, demonstrating the drive to adapt and be at the forefront of future technology challenges.
- Construction of the IOR (Improved Oil Recovery) centre at Rotvoll (2,000 square metres) has started. A technology centre devoted to develop IOR technologies will help us to reach the 60% IOR ambition on the NCS.
- Mongstad Technology Centre opened in May 2012. The Mongstad Technology Centre is unique in the global context with its capacity to capture up to 100,000 tonnes of carbon annually from two different exhaust gas streams, using two different capturing technologies.

Technology excellence

The technology excellence (TEX) business cluster 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, reduced costs and improved drilling efficiency. Technology excellence also supports innovators and entrepreneurs in connection with technology development and commercialisation activities.

Selected technology advances and important milestones in 2012:

- Enhanced recovery through subsea compression on the Gullfaks South field. This technological leap forward represents an important milestone in the efforts to improve recovery from this and other gas fields.
- Remote-controlled hot tap operation world record at Åsgard. For the first time, remote-controlled machines and an underwater welding robot installed a new tie-in point on a live gas pipeline, without the pipeline being prepared in advance.
- TVCM - Tordis Vigdis Control System Modifications. Statoil has for the first time replaced the control system in older wells on subsea fields, resulting in significantly longer lifetime for such fields.
- Fast Model Update (FMU): new technology has made building maintenance and the running of reservoir models much more efficient.
- The high focus on developing new technology has resulted in an increased number of technologies being ready for implementation.

Projects

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

PRO aims for world-class project performance, delivering cost-efficient projects on time and in accordance with high HSE standards and agreed quality standards.

PRO continues to emphasise competitive cost and quality in design and execution, to drive performance and be prepared to face the fierce competition of the future. Considerable effort is put into setting the direction of the key drivers in Statoil's projects in the early phase, when the impact on value creation is higher.

Experience transfer from fast-track projects is essential, in particular in relation to simplification and swift implementation of improvements. Fast-track projects are subsea tie-in projects in which standardised solutions are used to shorten the time from discovery to production from five to 2.5 years, thus reducing execution costs.

PRO keeps up the momentum in simplification and standardisation to ensure lean and agile project development. Substantial economies of scale are achieved through management and procurement strategies across projects. PRO continues to emphasise the development of cross-functional expertise and learning across projects, prerequisites for staying lean and capitalising on synergies.

Statoil has an attractive project portfolio comprising around 100 projects in the early phase and 50 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. The first field decommissioning projects on the NCS are in progress.

Important milestones in 2012:

- Start-up of Sheringham shoal offshore wind farm, located close to the planned Dudgeon offshore wind power project.
- Marulk and the first fast-track project, Visund South, started production in 2012.
- Completion of Mongstad technology centre, Mongstad delayed coker revamp and Åsgard gas transfer.
- The challenging replacement of risers on Visund, Snorre B and Njord was successfully completed.
- Oseberg C drilling facility upgrade, Oseberg D heat recovery steam generator and Peregrino salt and sulphate removal were completed.
- The Troll A living quarters extension was completed, and Troll A 3&4 compressor progressed through 2012.
- The cutting-edge technology project, Åsgard subsea compression, received the Offshore Northern Seas Conference (ONS) 2012 innovation award for making a technological leap in subsea processing.
- Gudrun and Valemon continued to progress throughout 2012.
- The following projects entered the execution phase in 2012: Aasta Hansteen, Gina Krog (formerly Dagny), Mariner and the gas infrastructure project Polarled, Gullfaks subsea compression and the fast-track projects Gullfaks South improved oil recovery, Svalin and Fram H-North, Gullfaks B drilling upgrade, the Snorre and Grane permanent monitoring system, Gullfaks B drilling facilities upgrade and Statfjord B/C fire and gas safety automation system upgrade.

Drilling and well

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

D&W focuses on industrialisation of our drilling operations by exploiting new technologies for intelligent and safe well construction. D&W will continue to aim for enhanced operational excellence, and the outlook going forward indicates continuous strong growth in activity.

We experienced good HSE results and significant efforts have been made to further develop the compliance and leadership culture in parallel with simplifying and improving our work processes.

Important deliveries in 2012:

- 75 offshore wells drilled in 2012, including 12 international and 10 NCS exploration wells.
- 42 rig years operated in 2012, an increase of five rig years from 2011.
- 162 onshore explorations wells in Canada during the winter drilling programme.
- Continuing development of new types of fit-for-purpose rigs especially designed for use on mature fields on the NCS to secure future rig capacity.

Procurement and supplier relations

Procurement and supplier relations (PSR) is responsible for ensuring cost-efficient procurement on a global basis that is aligned with Statoil's business needs, and for managing Statoil's supply chain. The annual value of Statoil's procurements (spend) is more than NOK 140 billion from approximately 12,000 active suppliers.

The procurement process is based on competition and the principles of openness, non-discrimination and equality. Our suppliers contribute significant value to Statoil, and to our partners and customers. 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. The procurement organisation was reorganised in November 2012 in order to be more efficient and contribute to achieving Statoil's ambition. We have enhanced our supplier relations management approach by improving internal processes, held structured compliance and leadership training sessions with suppliers, and maintained a strong focus on HSE and performance management.

Local content

Our main suppliers and contractors have a large number of sub-suppliers, both in Norway and internationally, so the ripple effects of contracts with Statoil can be large. We promote local deliveries and cooperate with local companies as contractors and suppliers where these are available. We also invest in the development of sustainable and competitive local companies. We support the development of expertise in local communities and among our suppliers and contractors in order to build up lasting expertise and help them to develop the standards and certification schemes required for work in the oil and gas industry.

Important milestones in 2012:

- Contract awards on light well intervention vessels (cat A), the increased oil recovery machine (cat B) and two additional semi-submersibles for medium water depths (cat D).
- Tender process initiated for a new jack-up rig concept for shallow water (cat J).
- Contract awards in Statoil's maintenance and modification portfolio.
- Familiarisation process with suppliers for Aasta Hansteen, Gina Krog (formerly Dagny), Mariner and Bressay field concepts.
- Contract awards for Mariner.
- New agreements on drilling services for fixed installations, integrated drilling services and electric wireline logging services.

3.9.3 Corporate Staffs and Services

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

They include headquarters and central functions that provide business support such as finance, human resources, information technology, legal services, communications and investor relations activities.

3.10 Significant subsidiaries

The following table shows significant subsidiaries and associated companies as of 31 December 2012.

Our voting interest in each case 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 Outer Shelf AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 31 AS	100	Norway	Statoil North America Inc.	100	United States
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 Methanol ANS	82	Norway
Statoil Hassi Mouina AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Indonesia Karama AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil New Energy AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Nigeria AS	100	Norway	Naturkraft AS	50	Norway
Statoil Nigeria Deep Water AS	100	Norway	Vestprosess DA	34	Norway

3.11 Production volumes and prices

The business overview is in accordance with our segment's operations as of 31 December 2012, 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*.

3.11.1 Entitlement production

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

The following table shows our Norwegian and international entitlement production of oil and natural gas for the periods indicated. The stated production volumes are the volumes that Statoil is entitled to 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 the year ended 31 December		
Entitlement production	2012	2011	2010
Norway			
Oil and NGL (mmbbls)	231	252	256
Natural gas (bcf)	1,483	1,287	1,370
Natural gas (bcm)	42.0	36.5	38.8
Combined oil and gas (mmboe)	495	481	500
Eurasia excluding Norway			
Oil and NGL (mmbbls)	17	15	18
Natural gas (bcf)	62	48	51
Natural gas (bcm)	1.8	1.4	1.4
Combined oil and gas (mmboe)	28	23	27
Africa			
Oil and NGL (mmbbls)	56	46	53
Natural gas (bcf)	41	40	41
Natural gas (bcm)	1.2	1.1	1.2
Combined oil and gas (mmboe)	63	53	60
Americas			
Oil and NGL (mmbbls)	50	31	26
Natural gas (bcf)	161	59	47
Natural gas (bcm)	4.6	1.7	1.3
Combined oil and gas (mmboe)	79	41	34
Total			
Oil and NGL (mmbbls)	353	343	352
Natural gas (bcf)	1,748	1,434	1,509
Natural gas (bcm)	49.5	40.6	42.8
Combined oil and gas (mmboe)	665	598	621

3.11.2 Production costs and sales prices

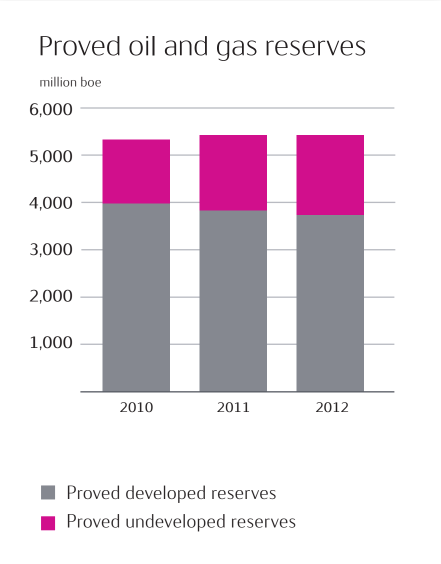
The following tables present the average unit of production cost based on entitlement volumes and realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 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	51
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	74
Year ended 31 December 2010				
Average sales price liquids in USD per bbl	76.3	79.1	76.8	75.1
Average sales price natural gas in NOK per Sm3	1.8	0.6	1.6	1.0
Average production cost in NOK per boe	41	42	49	66

3.12 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,422 mmboe at year end 2012, compared to 5,426 mmboe at the end of 2011.

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 to the Consolidated financial statements, *Significant accounting policies*. For further details on proved reserves, see also note 30 to the Consolidated financial statements, *Supplementary oil and gas information*.



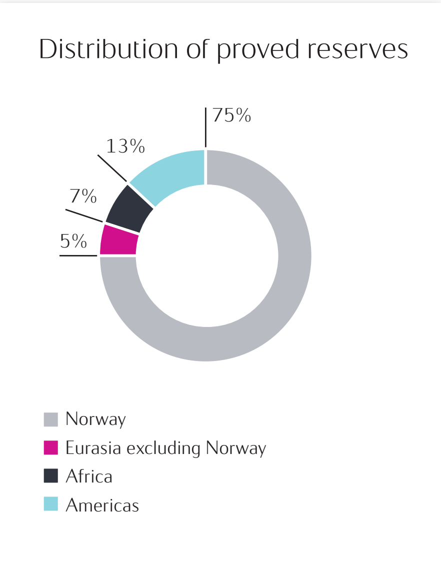
Changes in proved reserves estimates are most commonly the result of revisions of estimates due to observed production performance, extensions of proved areas through drilling activities or the inclusion of proved reserves in new discoveries through the sanctioning of development projects. These are 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, we recognise 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 87% of our proved reserves are located in OECD countries. Norway is by far the most important contributor in this category, followed by the United States of America (USA), the United Kingdom (UK), Canada and Ireland. The proved reserves in the UK have increased considerably due to sanctioning of the Mariner field development project.



Nine per cent of our total proved reserves 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 approximately 3% of our total proved reserves. They are included in proved reserves in the Americas.

Significant additions to our proved reserves in 2012 were:

- Positive revisions due to production experience, further drilling and improved recovery have increased the proved reserves in several of our producing assets, including Ormen Lange, Statfjord, Oseberg, Tyrihans, Åsgard, Gjøa, the Gullfaks satellites and Sleipner Vest in Norway, Agbami in Nigeria, ACG and Shah Deniz in Azerbaijan, and several fields in Angola. This added a total of 353 million boe in 2012.
- Proved reserves from new discoveries have also been added through the sanctioning of new field development projects such as the Mariner field in the UK, the Hebron field in Canada and the Gina Krog (formerly Dagny) and Ivar Aasen fields in Norway.
- Further drilling in the Bakken, Marcellus and Eagle Ford onshore plays in the USA increased the proved reserves in 2012, and these additions are presented as extensions. Extensions together with the newly sanctioned discoveries added a total of 378 million boe of new proved reserves in 2012.

The 2012 entitlement production was 665 million boe, an increase of 11% compared to 2011. New discoveries with proved reserves booked in 2012 are all expected to start production within a period of five years.

Summary of proved oil and gas reserves as of 31 December 2012

Reserves category	Proved reserves Oil and NGL (mmbbls)	Natural Gas (bcf)	Total oil and gas (mmboe)
Developed			
Norway	842	12,073	2,994
Eurasia excluding Norway	79	343	140
Africa	232	226	272
Americas	229	567	331
Total Developed proved reserves	1,383	13,210	3,737
Undeveloped			
Norway	530	2,931	1,052
Eurasia excluding Norway	114	232	155
Africa	67	115	88
Americas	294	540	391
Total Undeveloped proved reserves	1,006	3,817	1,686
Total proved reserves	2,389	17,027	5,422

Our proved reserves of bitumen in the Americas are included as oil in the table above since they represent less than 3% of our proved reserves, which is regarded as immaterial.

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

Reserves replacement

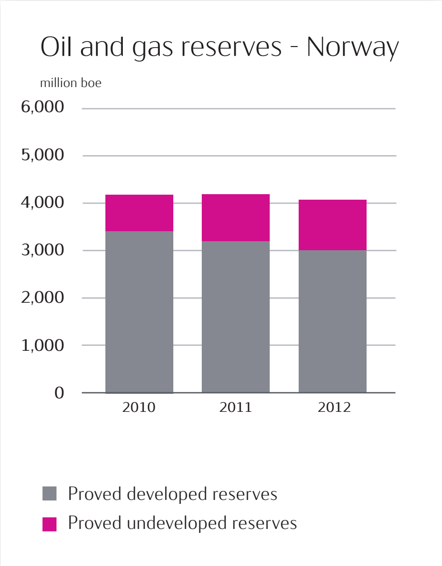
The reserves replacement ratio is defined as the sum of additions and revisions of proved reserves divided by produced volumes in any given period. The following table presents the changes in reserves in each category relating to the reserve replacement ratio for the years 2012, 2011 and 2010.

(million boe)	For the year ended 31 December 2012	2011	2010
Revisions and improved recovery	353	373	183
Extensions and discoveries	378	232	343
Purchase of petroleum-in-place	4	161	12
Sales of petroleum-in-place	(74)	(66)	0
Total reserve additions	661	700	538
Production	(665)	(598)	(621)
Net change in proved reserves	(4)	101	(84)

The reserves replacement ratio for 2012 was 0.99 compared to 1.17 in 2011. The 2012 reserves replacement ratio, excluding purchases and sales of petroleum in place, was 1.10. The average replacement ratio for the last three years was 1.01, or 0.99 excluding purchases and sales.

Reserves replacement ratio (including purchases and sales)	For the year ended 31 December 2012	2011	2010
Annual	0.99	1.17	0.87
Three-year-average	1.01	0.92	0.64

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.

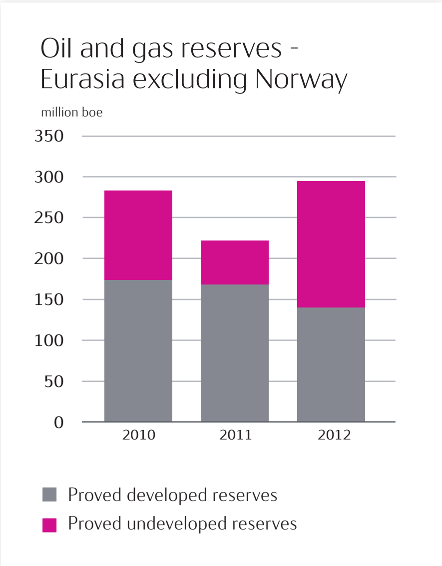


Proved reserves in Norway

A total of 4,046 million boe is recognised as proved reserves in 57 fields and field development projects on the Norwegian continental shelf (NCS), representing 75% of our total proved reserves. Of these, 46 fields and field areas are currently in production, 38 of which are operated by Statoil. Two new field development projects sanctioned during 2012, Gina Krog (formerly Dagny) and Ivar Aasen, have added new proved reserves categorised as extensions and discoveries. Production experience, further drilling and improved recovery on several of our producing fields in Norway also contributed positively to the revisions of the proved reserves in 2012.

Sales of reserves are mainly related to an agreement with Centrica to sell interests in certain licences in Norway. This has reduced Statoil's share of proved reserves on Kvitebjørn and Valemon and removed Skirne and Vale from the proved reserves accounts. Production on Heimdal has been temporarily shut down since 2011 and no proved reserves are included for Heimdal in 2012.

Of the proved reserves on the NCS, 2,994 million boe, or 74%, are proved developed reserves. Of the total proved reserves, 66% are gas reserves related to large offshore gas fields such as Troll, Oseberg, Ormen Lange, Snøhvit, Åsgard, Tyrihans, Visund and Kvitebjørn, and 34% are oil reserves.

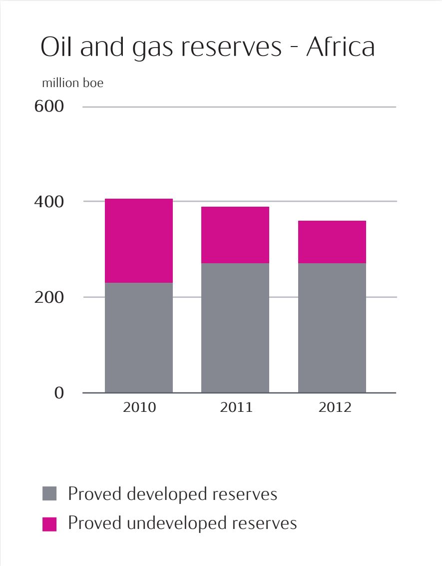


Proved reserves in Eurasia, excluding Norway

In this area, we have proved reserves of 296 million boe related to seven fields and field developments in the countries Azerbaijan, the United Kingdom (UK), Ireland and Russia. Eurasia excluding Norway represents 5% of our 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 2014 at the earliest, and the Mariner field in the UK, which is expected to start production in 2017.

Of the proved reserves in Eurasia, 140 million boe or 47% are proved developed reserves. Of the total proved reserves in this area, 65% are oil reserves and 35% are gas reserves. The oil share has increased significantly since 2011 through sanctioning of the Mariner field development in the UK.

Proved reserves in Africa



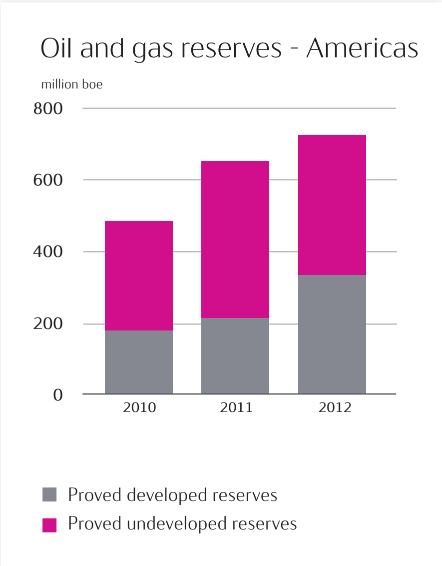
We recognise proved reserves of 360 million boe related to 23 fields and field developments in several West and North African countries, including Algeria, Angola, Libya and Nigeria. Africa represents 7% of our total proved reserves. Angola is the primary contributor to the proved reserves in this area, with 18 of the 23 fields.

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

In Angola, we have 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, are still under development. The Kizomba Satellites in Block 15 and the PSVM project in Block 31 started production in 2012.

Of the total proved reserves in Africa, 272 million boe, or 76%, 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, we have proved reserves equal to 721 million boe in a total of 16 fields and field development projects. This represents 13% of our 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. An important contribution in this area in 2012 is the sanctioning of the Hebron project in Canada, which added new proved reserves.

In the USA, three of the six fields in the Gulf of Mexico are in production. The Caesar Tonga field started production in 2012. Field development is ongoing on Big Foot, Jack 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 2012, which are expressed as extensions and discoveries.

In Canada, proved reserves are related both to offshore field developments, including the newly sanctioned Hebron project, and to the Leismer Demonstration Project in our oil sands leases in Alberta.

Of the total proved reserves in the Americas, 331 million boe, or 46%, are proved developed reserves. Of the total proved reserves in this area, 73% are oil reserves and 27% gas reserves.

3.12.1 Development of reserves

In 2012, we converted approximately 300 million boe from undeveloped to developed proved reserves.

The start-up of production from the Caesar Tonga field in the USA, the Kizomba satellites (Clochas and Mavacola) and PSVM in Angola and Marulk and Visund Sør in Norway increased our developed reserves by 78 million boe during 2012. The rest of the converted volume is related to development activities on producing fields.

The sanctioning of new projects, such as Gina Krog (formerly Dagny) and Ivar Aasen in Norway, Mariner in the UK and Hebron in Canada, added a total of 236 million boe of proved undeveloped reserves in 2012.

		Oil and NGL (mmbbls)	Natural gas (bcf)	Total (mmboe)
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
2010	**Proved reserves end of year**	**2,124**	**17,965**	**5,325**
	Developed	1,356	14,698	3,975
	Undeveloped	767	3,267	1,350

As of 31 December 2012, the total proved undeveloped oil and gas reserves amounted to 1,686 million boe, 62% of which are related to fields in Norway. The Snøhvit, Troll and Tyrihans fields, which have continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Gina Krog (formerly Dagny), Skarv, Gudrun, Skuld, Ivar Aasen and Goliat. The total proved undeveloped reserves for Norway increased in 2012, and this is linked both to the inclusion of the new developments sanctioned in 2012 and to positive revisions for several of our producing fields. The largest assets with respect to undeveloped proved reserves outside Norway are Mariner in the UK, the US onshore developments in Bakken, Marcellus and Eagle Ford, Peregrino in Brazil and Petrocedeño in Venezuela.

In 2012, Statoil incurred NOK 89 billion in development costs relating to assets carrying proved reserves, NOK 68 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 in Azerbaijan, Leismer oil sands in Canada 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.

Since some of our newly sanctioned field developments, such as Mariner in the UK and Hebron in Canada, fall into the same category and will require continued drilling of wells over a long period of time, these also include reserves that will require more than five years to be developed. One of our fields with undeveloped proved reserves, 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 2014.

Additional information about proved oil and gas reserves is provided in note 30 to the Consolidated financial statements, *Supplementary oil and gas information*.

3.12.2 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 our own 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 our 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 for consistency and conformity with applicable standards by CRM. 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 27 years' experience in the oil and gas industry, 26 of them with Statoil. She is a member of the Norwegian Petroleum Society 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 2012. The evaluation accounts for 99.9% of Statoil's proved reserves. It does not include reserves related to the acquisition of an operatorship in the Marcellus play in late 2012. 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 2012	Oil, Condensate and LPG (mmbbls)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,388	17,009	5,418
Estimated by DeGolyer and MacNaughton	2,348	17,649	5,493

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

3.12.3 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 2012.

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 2012		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells						
Oil wells	— gross	930	175	384	1,611	3,100
	— net	376.5	31.1	56.7	990.3	1,454.6
Gas wells	— gross	192	10	75	888	1,165
	— net	86.2	2.8	28.4	239.0	356.4

The total gross number of productive wells at the end of 2012 includes 463 oil wells and 25 gas wells with multiple completions or wells with more than one branch.

At 31 December 2012 (in thousands of acres)		Norway	Eurasia excluding Norway	Africa	Americas	Total
Developed and undeveloped oil and gas acreage						
Acreage developed	— gross	809	110	1,026	637	2,582
	— net	307	21	306	266	900
Acreage undeveloped	— gross	9,325	25,076	20,463	11,239	66,103
	— net	4,230	8,439	7,510	4,829	25,008

The largest concentrations of developed acreage in Norway are in the Troll, Ormen Lange, Snøhvit 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).

Our largest undeveloped acreage concentration in Eurasia excluding Norway is in Indonesia, with 54% of the total for this geographical area. Our largest acreage concentration in Africa is in Angola, representing about half 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 wells in which hydrocarbons were discovered, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or 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 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
Year 2010					
Net productive and dry exploratory wells drilled	10.0	0.4	1.4	3.3	15.0
— Net dry exploratory wells drilled	3.1	0.4	0.7	1.9	6.0
— Net productive exploratory wells drilled	6.9	0.0	0.8	1.4	9.0
Net productive and dry development wells drilled	26.0	3.3	8.4	54.2	91.9
— Net dry development wells drilled	2.0	0.0	0.2	0.0	2.2
— Net productive development wells drilled	24.0	3.3	8.2	54.2	89.7

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 2012.

At 31 December 2012		Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of wells in progress						
Development Wells	— gross	54	7	18	399	478
	— net	22.2	0.8	4.2	165.1	192.3
Exploratory Wells	— gross	4	2	2	3	11
	— net	1.8	0.5	0.9	1.3	4.5

3.12.4 Delivery commitments

This section describes the long-term NCS commitments for the contract years 2012-2015.

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 our 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 2012, the long-term commitments from NCS for the Statoil/SDFI arrangement totalled approximately 17.65 tcf (500 bcm).

Statoil and SDFI's delivery commitments, expressed as the sum of expected off-take for the gas years 2012, 2013, 2014 and 2015, are 2.4, 1.9, 1.8 and 1.7 tcf (68.8, 54.5, 51.4 and 48.8 bcm), respectively.

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

3.13 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 and to further develop the company. 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.

3.13.1 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 licencing 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.

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.

3.13.2 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*.

3.13.3 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.

Following the incident that occurred on the BP-operated Macondo well in the deepwater Gulf of Mexico, USA, in April 2010, the Norwegian Ministry of Petroleum and Energy announced that the incident could result in changes to laws and regulations concerning activities on the NCS. After a review of the regulations, no changes have been imposed so far.

However, on 27 October 2011, the European Commission proposed a new offshore safety regulation with the objective of reducing the risk of a major incident in European Union (EU) waters and limiting the consequences should such an incident occur. The draft regulation is now subject to a consultation procedure among the EU Member States, which is not expected to conclude until late 2013. If enforced in the EU, it will have a direct impact on our offshore upstream operations in the EU, and if subsequently adopted in the European Economic Area (EEA), of which Norway is part, the regulation would also apply to our activities on the NCS. Its effects, if any, are not possible to foresee until the legislative process is finalised.

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.

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

3.13.4 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 corporate income tax rate is currently 28%. 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 financial costs 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. Fifty per cent of losses relating to activity conducted onshore in Norway can be deducted from NCS income subject to the 28% tax rate. 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. From 2012 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 based on the full amounts received.

From 2012, 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 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 is currently levied at a rate of 50%. The special tax is applied to relevant income in addition to standard 28% income tax, 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. 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.

With effect from 1 January 2012, new legislation enacted in Norway exempts income and deductions related to foreign petroleum activity from Norwegian taxation.

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. 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. 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 in addition to tax based on the company's net taxable income from production. In general, the fiscal terms surrounding these licences are non-negotiable and the company is subject to legislative changes in the tax laws.

3.13.5 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.

3.13.6 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.

3.14 Property, plants 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 30 to the Consolidated financial statements, *Supplementary oil and gas information (unaudited)*.

3.15 Related party transactions

See note 27 Related parties to the Consolidated financial statements for information concerning related parties.

3.16 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 7,800 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 varies between NOK 7.6 million and NOK 100 million per loss on the NCS depending on our percentage ownership interest in the well and certain other factors. 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.

3.17 People and the group

3.17.1 Employees in Statoil

The Statoil group employs approximately 23,000 employees. Of these, approximately 20,200 are employed in Norway and approximately 2,800 outside Norway.

Numbers of permanent employees and percentage of women in the Statoil group from 2010 to 2012

	Number of employees*			Women*		
Geographical Region	2012	2011	2010	2012	2011	2010
Norway	**20,186**	20,021	18,838	30%	31%	31%
Rest of Europe	**925**	10,187	10,335	30%	50%	49%
Africa	**116**	121	140	25%	28%	30%
Asia	**157**	146	145	56%	59%	58%
North America	**1,378**	1,030	713	34%	34%	33%
South America	**266**	210	173	38%	40%	46%
TOTAL	**23,028**	31,715	30,344	31%	37%	37%
Non - OECD	**653**	2,773	2,732	39%	64%	63%

* Statoil Fuel and Retail employees are included in 2010 and 2011.

Total workforce by region, employment type and new hires in the Statoil group in 2012

Geographical Region	Permanent employees	Consultants	Total Workforce*	% Consultants**	% Part - Time	New Hires
Norway	20,186	2,549	22,735	11%	3%	1,661
Rest of Europe	925	165	1,090	15%	1%	100
Africa	116	53	169	31%	NA	15
Asia	157	14	171	8%	NA	31
North America	1,378	54	1,432	4%	NA	344
South America	266	148	414	36%	NA	69
TOTAL	23,028	2,983	26,011	11%	3%	2,220
Non - OECD	653	230	883	26%	NA	120

* Total workforce consists of number of permanent employees and consultants.
** Consultants do not include enterprise personnel.

Statoil works systematically with recruitment and development programmes in order to build a diverse workforce by attracting, recruiting and retaining people of both genders and different nationalities and age groups across all types of positions. In 2012, Statoil recruited 2,220 new employees worldwide. While 75% were recruited to jobs in Norway, 15% 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 2012 was 2.2%.

3.17.2 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 2012 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 strengthening women in leadership and professional positions and building broad international experience in our workforce.

At 31 December 2012, the overall percentage of women in Statoil was 31% and 36% of the members of the board of directors were women, as were 20% of the corporate executive committee. The focus on diversity issues is also reflected in the company's people strategy. We aim to increase the number of female managers, and we endeavour to give equal representation to men and women in leadership development programmes. At 31 December 2012, the total proportion of female managers in Statoil was 27%.

We also devote close attention to male-dominated positions and discipline areas. In 2012, 26% of staff engineers were women, and among staff engineers with up to 20 years' experience, the proportion of women was 30%.

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 2012, 30% of our new hires were women and 41% 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 long-term, extensive use of expats in our business operations. At 31 December 2012, 20% of employees and 20% of the managerial staff in the Statoil group held nationalities other than Norwegian.

3.17.3 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, 65% 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 2012, management and employee representatives collaborated closely in processes such as the use of external hires, the corporate staffs and services review project and measures to follow up safety incidents on the Norwegian continental shelf. In these processes we have endeavoured to engage in open and honest communication both inside and outside formal meeting arenas.

4 Financial review

4.1 Operating and financial review 2012

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 2012	2011	2010
Statoil: (1)			
Crude oil (mmbbls) (2)	351	332	354
Natural gas (bcf)	1,721	1,377	1,472
Natural gas (bcm) (3)	48.8	39.0	41.7
Combined oil and gas (mmboe)	658	577	616
Third party volumes: (4)			
Crude oil (mmbbls)(2)	399	333	310
Natural gas (bcf)	210	244	247
Natural gas (bcm) (3)	6.0	6.9	7.0
Combined oil and gas (mmboe)	436	376	354
SDFI assets owned by the Norwegian State:			
Crude oil (mmbbls) (2)	156	162	172
Natural gas (bcf)	1,591	1,476	1,610
Natural gas (bcm) (3)	45.1	41.8	45.6
Combined oil and gas (mmboe)	439	425	458
Total:			
Crude oil (mmbbls) (2)	905	827	835
Natural gas (bcf)	3,523	3,096	3,329
Natural gas (bcm) (3)	99.8	87.7	94.3
Combined oil and gas (mmboe)	1,533	1,379	1,428

(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 such 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) At a gross calorific value (GCV) of 40 MJ/scm.

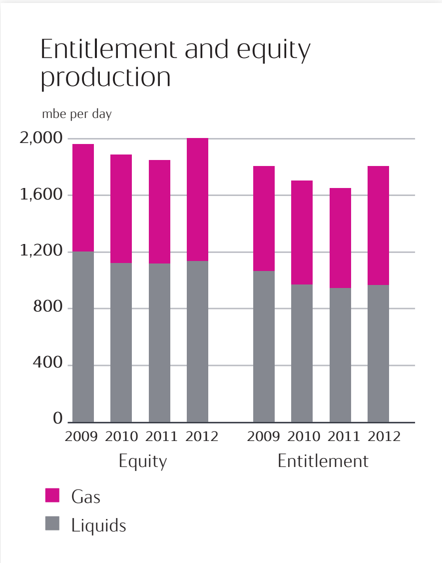
(4) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG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

4.1.2 Group profit and loss analysis

Net operating income was NOK 206.6 billion in 2012, down 2% compared to 2011. Higher prices and increased volumes were offset by lower gain from sale of assets and increased operational costs.

Operational review

Operational data	For the year ended 31 December 2012	2011	2010	12-11 change	11-10 change
Average liquids price (USD/bbl)	**103.5**	105.6	76.5	(2%)	38%
USDNOK average daily exchange rate	**5.82**	5.61	6.05	4%	(7%)
Average liquids price (NOK/bbl)	**602**	592	462	2%	28%
Average invoiced gas prices (NOK/scm)	**2.19**	2.08	1.72	5%	21%
Refining reference margin (USD/bbl)	**5.5**	2.3	3.9	>100%	(41%)
Production (mboe per day)					
Entitlement liquids production	**966**	945	968	2%	(2%)
Entitlement gas production	**839**	706	738	19%	(4%)
Total entitlement liquids and gas production	**1,805**	1,650	1,705	9%	(3%)
Equity liquids production	**1,137**	1,118	1,122	2%	(0%)
Equity gas production	**867**	732	766	18%	(4%)
Total equity liquids and gas production	**2,004**	1,850	1,888	8%	(2%)
Liftings (mboe per day)					
Liquids liftings	**959**	910	969	5%	(6%)
Gas liftings	**839**	706	738	19%	(4%)
Total liquids and gas liftings	**1,797**	1,616	1,706	11%	(5%)
Production cost (NOK/boe, last 12 months)					
Production cost entitlement volumes	**47**	47	42	(1%)	12%
Production cost equity volumes	**42**	42	38	(0%)	11%



Total equity liquids and gas production (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 2,004 mboe, 1,850 mboe and 1,888 mboe per day in 2012, 2011 and 2010, respectively.

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.

The 2% decrease in total equity production in 2011 compared to 2010 was primarily caused by reduced water injection at Gullfaks, riser inspections and repairs, maintenance shut downs and deferral of gas sales. In addition, expected reductions due to natural decline on mature fields and suspended production in Libya contributed to the decrease. This decrease was partly offset by production from start-up of new fields, ramp-up of production on existing fields and increased ownership shares.

Total entitlement liquids and gas production (see section *Financial review - Operating and financial review - Definition of reported volumes*) increased 9% from 1,650 mboe per day in 2011 to 1,805 mboe per day in 2012. Total entitlement liquids and gas production decreased by 3% from 2010 to 2011, impacted by the reduction in equity production as described above and volume reducing PSA effects.

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 47, NOK 47 and NOK 42 for the 12 months ended 31 December 2012, 2011 and 2010, respectively.

Based on equity volumes, the production cost per boe was NOK 42, NOK 42 and NOK 38 for the 12 months ended 31 December 2012, 2011 and 2010, 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 expenditure (including capitalised exploration expenditure) was NOK 20.9 billion in 2012, compared to NOK 18.8 billion in 2011 and NOK 16.8 billion in 2010. The NOK 2.1 billion increase in 2012 stems mainly from both higher drilling activity internationally and increased field evaluation costs, partly offset by lower activity on the NCS.

In 2012, Statoil completed 46 **exploration and appraisal wells**, 19 on the NCS and 27 internationally. A total of 23 wells were announced as discoveries in the period, 14 on the NCS and nine internationally.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2012	2011	2010	12-11 change	11-10 change
Revenues	**705.7**	645.6	527.0	9%	23%
Net income from associated companies	**1.7**	1.3	1.2	32%	8%
Other income	**16.0**	23.3	1.8	(31%)	>100%
Total revenues and other income	**723.4**	670.2	529.9	8%	26%
Purchases [net of inventory variation]	**(363.1)**	(319.6)	(257.4)	14%	24%
Operating expenses and selling, general and administrative expenses	**(75.1)**	(73.6)	(68.8)	2%	7%
Depreciation, amortisation and net impairment losses	**(60.5)**	(51.4)	(50.7)	18%	1%
Exploration expenses	**(18.1)**	(13.8)	(15.8)	31%	(12%)
Net operating income	**206.6**	211.8	137.3	(2%)	54%
Net financial items	**0.1**	2.0	(0.5)	(95%)	>(100%)
Income before tax	**206.7**	213.8	136.8	(3%)	56%
Income tax	**(137.2)**	(135.4)	(99.2)	1%	37%
Net income	**69.5**	78.4	37.6	(11%)	>100%

Total revenues and other income amounted to NOK 723.4 billion in 2012 compared to NOK 670.2 billion in 2011 and NOK 529.9 billion in 2010. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil. In addition, we also 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 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.

The 26% increase in revenues from 2010 to 2011 was mainly attributable to higher prices for both liquids and gas and unrealised net gains on derivatives. The increase was partly offset by lower volumes of both liquids and gas sold.

Other income was NOK 16.0 billion in 2012 compared to NOK 23.3 billion in 2011 and NOK 1.8 billion in 2010. The NOK 7.3 billion decrease from 2011 to 2012 was mainly due to 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.

The significant increase in other income from 2010 to 2011 stems mainly from gains on sale of assets primarily related to the divestments mentioned above.

Purchases [net of inventory variation] includes the cost of the liquids production purchased from the Norwegian State pursuant to the owners instruction. See section *Business overview - Applicable laws and regulations- SDFI oil & gas marketing & sale* for more details. The purchase [net of inventory variation] amounted to NOK 363.1 billion in 2012, compared to NOK 319.6 billion in 2011 and NOK 257.4 billion in 2010. Both the 24% increase from 2010 to 2011 and the 14% increase from 2011 to 2012 were 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 75.1 billion, up 2% compared to 2011, mainly due to higher operating plant costs from start-up and ramp-up of production on various fields. Also, increased royalty payments, 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. 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, partly offset the increase.

In 2011, operating expenses and selling, general and administrative expenses amounted to NOK 73.6 billion, an increase of NOK 4.8 billion compared to 2010 when operating expenses and selling, general and administrative expenses were NOK 68.8 billion. The 7% increase reflects mainly the higher activity level in 2011 related to start-up and ramp-up of production on various fields, increased transportation and processing costs and increased ownership shares. Also, changes in removal estimates, higher tariffs and royalties paid and increased business development costs added to the increase in expenses.

Depreciation, amortisation and net impairment losses amounted to NOK 60.5 billion in 2012 compared to NOK 51.4 billion in 2011 and NOK 50.7 billion in 2010. Included in these totals were net impairment losses of NOK 1.3 billion for 2012, NOK 2.0 billion for 2011 and NOK 4.8 billion for 2010.

Depreciation, amortisation and net impairment losses increased by 18% compared to 2011 mainly because of higher depreciation because of 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.

Depreciation, amortisation and net impairment losses increased by 1% in 2011 compared to 2010 mainly because of higher depreciation from new fields and assets coming on stream, and the impact on depreciation from revisions of removal and abandonment estimates. The increase was mostly offset by the impact of lower production, increased reserve estimates and lower net impairment losses.

Exploration expenses (in NOK billion)	For the year ended 31 December 2012	2011	2010	12-11 Change	11-10 Change
Exploration expenditure (activity)	20.9	18.8	16.8	11%	12%
Expensed, previously capitalised exploration expenditure	2.7	1.8	2.6	49%	(30%)
Capitalised share of current periods exploration activity	(5.9)	(6.4)	(3.9)	(8%)	64%
Impairment	0.5	1.6	1.9	(71%)	(19%)
Reversal of impairment	(0.1)	(1.9)	(1.6)	(97%)	14%
Exploration expenses	18.1	13.8	15.8	31%	(12%)

In 2012, **exploration expenses** were NOK 18.1 billion, a NOK 4.3 billion increase since 2011, when exploration expenses were NOK 13.8 billion. Exploration expenses were NOK 15.8 billion in 2010.

The 31% increase in exploration expenses was mainly due to higher drilling activity in the international business, increased spending on seismic and field evaluation and because a lower portion of exploration expenditures was 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.

Exploration expenses decreased by 12% in 2011 compared to 2010, mainly because successful drilling resulted in a higher portion of exploration expenditures being capitalised, and because a lower portion of exploration expenditure capitalised in previous years was expensed in 2011 compared to 2010.

Net operating income was NOK 206.6 billion in 2012, compared to NOK 211.8 billion in 2011 and NOK 137.3 billion in 2010.

The 2% decrease from 2011 to 2012 was mainly attributable to decreased gains from sales of assets and decreased unrealised gains on derivatives. Higher exploration costs, increased depreciation costs and other operating expenses reflecting the overall increased activity level added to the decrease. Higher liquids and gas prices measured in NOK and increased volumes sold due to increased production and liftings, partly offset the decrease.

The 54% increase from 2010 to 2011 was primarily attributable to higher prices for both liquids and gas, reduced net impairment losses, unrealised gains on derivatives and gains on sale of assets mainly related to the reduction of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled in 2011. Lower volume of both liquids and gas sold and increased operating expenses partly offset the increase in net operating income.

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.

Net financial items amounted to a gain of NOK 2.0 billion in 2011, compared to a loss of NOK 0.5 billion in 2010. The increase was mainly due to positive changes in currency derivatives used for currency and liquidity risk management, and positive fair value changes on interest rate swap positions relating to the interest rate management of non-current bonds, offset by increased interest and other finance expenses, mainly due to the Pernis impairment and the Heidrun redetermination in 2011.

Income taxes were NOK 137.2 billion in 2012, equivalent to an effective tax rate of 66.4%, compared to NOK 135.4 billion in 2011, equivalent to an effective tax rate of 63.3%, and NOK 99.2 billion in 2010, equivalent to an effective tax rate of 72.5%.

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 decrease in the effective tax rate from 2010 to 2011 was mainly due to capital gains on sale of assets in 2011 with lower than average tax rates and recognition of previously unrecognised deferred tax assets in 2011. As part of the purchase price allocation (PPA) for the acquisition of Brigham Exploration Company an amount of NOK 8.7 billion of deferred tax liabilities was recognised. As a result of the recognition of these deferred tax liabilities, previously unrecognised deferred tax assets of NOK 3.1 billion related to deferred tax losses in other parts of the US operations were recognised in 2011.

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%, and income in other countries is taxed at the applicable income tax rates in those countries.

In 2012, the **non-controlling interest** in net profit was positive NOK 0.6 billion, compared to negative NOK 0.4 billion in 2011 and negative NOK 0.5 billion in 2010. The non-controlling interest in 2011 is primarily related to the 79% ownership of Mongstad crude oil refinery.

In 2012, **Net income** was NOK 69.5 billion compared to NOK 78.4 billion in 2011 and NOK 37.6 billion in 2010.

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 108% increase from 2010 to 2011 was mainly due to the increase in net operating income, positively impacted by higher liquids and gas prices. Also, gains from sale of assets, increased unrealised gains on derivatives, gains on net financial items and a lower effective tax rate contributed positively to the increase in net income. Lower volumes of liquids and gas sold and higher operating expenses partly offset the increase in net income compared to 2010.

The board of directors will propose for approval at the annual general meeting an **ordinary dividend** of NOK 6.75 per share for 2012, 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. In 2010, the ordinary dividend was NOK 6.25 per share, an aggregate total of NOK 19.9 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 the estimated market price.

The table below details certain financial information for our reporting segments. For additional information please refer to note 4 *Segments* in the Consolidated financial statements.

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.

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 inter-company 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.

In 2012, the average transfer price for natural gas was NOK 1.84 per scm. The average transfer price was NOK 1.64 per scm in 2011 and NOK 1.27 in 2010. For oil sold from DPN to MPR, the transfer price is the applicable market-reflective price minus a margin of NOK 0.70 per barrel.

The following table shows certain financial information for the five segments, including inter-company eliminations for each of the years in the three-year period ending 31 December 2012.

	For the year ended 31 December		
(in NOK billion)	2012	2011	2010
Development & Production Norway			
Total revenues and other income	**220.8**	212.1	170.7
Net operating income	**161.7**	152.7	115.6
Non-current segment assets*	**235.4**	211.6	188.2
Development & Production International			
Total revenues and other income	**82.9**	70.9	51.0
Net operating income	**21.5**	32.8	12.6
Non-current segment assets*	**248.2**	239.4	137.3
Marketing, Processing and Renewable Energy			
Total revenues and other income	**669.5**	610.0	493.6
Net operating income	**15.5**	24.7	6.1
Non-current segment assets*	**38.5**	34.5	55.2
Fuel & Retail**			
Total revenues and other income	**41.6**	73.7	65.9
Net operating income	**6.9**	1.9	2.4
Non-current segment assets*	-	10.8	11.1
Other			
Total revenues and other income	**1.3**	1.1	3.5
Net operating income	**2.6**	(0.3)	0.6
Non-current segment assets*	**4.5**	4.0	3.0
Eliminations***			
Total revenues and other income	**(292.6)**	(297.6)	(254.8)
Net operating income	**(1.6)**	(0.1)	(0.1)
Non-current segment assets*	-	-	-
Statoil group			
Total revenues and other income	**723.4**	670.2	529.9
Net operating income	**206.6**	211.8	137.3
Non-current segment assets*	**526.6**	500.3	394.7

* 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.

2012 Total revenues by geographic area (in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Norway	270,578	107,263	65,867	108,215	5,538	557,461
USA	68,807	6,836	2,717	21,871	7,186	107,417
Sweden	0	0	0	9,121	(342)	8,779
Denmark	0	0	0	18,118	86	18,204
Other	21,539	4,451	1,766	(0)	2,129	29,885
Total revenues (excluding net income (loss) from associated companies)	360,923	118,550	70,350	157,326	14,596	721,745

2011 Total revenues by geographic area (in NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Norway	269,457	87,713	58,757	62,368	38,089	516,384
USA	34,101	7,305	1,904	17,237	5,127	65,674
Sweden	0	0	0	17,699	4,953	22,652
Denmark	0	0	0	17,448	1,642	19,090
Other	11,586	3,946	1,606	14,036	13,967	45,141
Total revenues (excluding net income (loss) from associated companies)	315,144	98,964	62,267	128,788	63,778	668,941

2010 Total revenues by geographic area (in NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Norway	227,122	72,643	47,551	47,332	16,949	411,597
USA	22,397	7,817	1,815	14,918	5,771	52,718
Sweden	0	0	0	18,810	4,612	23,422
Denmark	0	0	0	14,275	3,027	17,302
Other	4,508	4,380	205	12,150	2,467	23,710
Total revenues (excluding net income (loss) from associated companies)	254,027	84,840	49,571	107,485	32,826	528,749

4.1.4 DPN profit and loss analysis

In 2012, Development and Production Norway (DPN) delivered solid financial results. DPN generated total revenues of NOK 220.8 billion in 2012 and its net operating income was NOK 161.7 billion.

The average daily entitlement production was 624 mboe per day for liquids and 710 mboe per day for gas.

Operational review

Operational data	For the year ended 31 December 2012	2011	2010	12-11 change	11-10 change
Prices					
Liquids price (USD/bbl)	104.5	105.6	76.3	(1%)	39%
Liquids price (NOK/bbl)	608.5	592.3	461.0	3%	28%
Transfer price natural gas (NOK/scm)	1.84	1.64	1.27	12%	29%
Production (mboe per day)					
Entitlement liquids	624	693	704	(10%)	(2%)
Entitlement natural gas	710	624	669	14%	(7%)
Total entitlement liquids and gas production	1,335	1,316	1,374	1%	(4%)
Liftings (mboe per day)					
Liquids liftings	632	673	711	(6%)	(5%)
Gas liftings	710	624	669	14%	(7%)
Total liquids and gas liftings	1,343	1,297	1,380	4%	(6%)

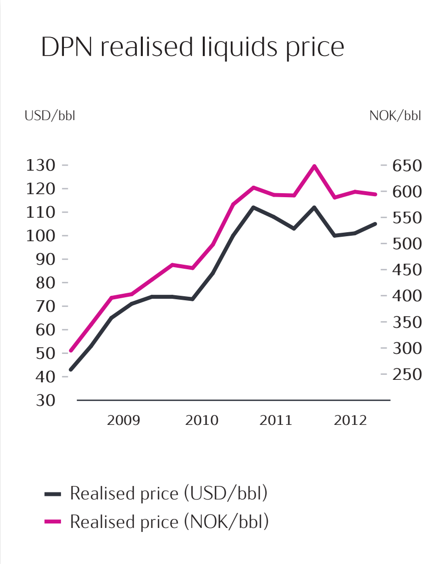
The average daily production of liquids and gas (see the section *Financial review - Operating and financial review - Definition of reported volumes*) was 1,335 mboe, 1,316 mboe and 1,374 mboe per day in 2012, 2011 and 2010, respectively. The average daily production of liquids and gas increased by 1% 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.

The average daily production of liquids and gas decreased by 4% from 2010 to 2011, mainly related to Gullfaks reduced water injection and turnaround, Visund turnaround and riser inspection and repair, and Volve shut down due to anchor problems. In addition, expected reductions due to natural decline on mature fields contributed to the decrease. These effects were partly offset by new production at Morvin, Vega and Gjøa, increased production at Tyrihans and Sleipner, low decline rate and increased ownership share at Heidrun.

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 2012	2011	2010	12-11 change	11-10 change
Total revenues and other income	220.8	212.1	170.7	4%	24%
Operating expenses and selling, general and administrative expenses	25.8	24.7	23.6	4%	5%
Depreciation, amortisation and net impairment losses	29.8	29.6	26.0	1%	14%
Exploration expenses	3.5	5.1	5.5	(31%)	(7%)
Total operating expenses	59.2	59.4	55.1	(0%)	8%
Net operating income	161.7	152.7	115.6	6%	32%



Total revenues and other income were NOK 220.8 billion in 2012, NOK 212.1 billion in 2011 and NOK 170.7 billion in 2010. A 14% increase in 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.

The 24% increase in total revenues and other income from 2010 to 2011 was mainly attributable to a 39% increase in the average price in USD of oil sold by DPN to MPR, accounting for NOK 43.8 billion, and an increased gas price in NOK of sold gas, making a positive contribution of NOK 13.4 billion in 2011. These effects were partly offset by a negative currency exchange rate deviation of NOK 11.5 billion due to a 7% decrease in the USD/NOK average daily exchange rate in 2011. Furthermore, a 5% decrease in lifted volumes of liquids negatively impacted revenues by NOK 5.2 billion and a 7% decrease in lifted volumes of gas negatively impacted revenues by NOK 3.4 billion.

Operating expenses and selling, general and administrative expenses were NOK 25.8 billion in 2012, compared to NOK 24.7 billion in 2011 and NOK 23.6 billion in 2010. In 2012, expenses increased mainly due to increased operating plant costs related to higher maintenance activity and well maintenance on some fields (especially Gullfaks and Åsgard). The increase of NOK 1.1 billion from 2010 to 2011 was due to transportation tariffs (Troll and Oseberg), increased ownership in Heidrun and new fields coming on stream (Beta West, Vega and Morvin). Operating plant costs remained stable compared to 2010.

Depreciation, amortisation and net impairment losses were NOK 29.8 billion in 2012, compared to NOK 29.6 billion in 2011 and NOK 26.0 billion in 2010. 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 re-determination at Heidrun. The NOK 3.6 billion increase from 2010 to 2011 was mainly related to new fields on stream, increased removal/abandonment estimates, re-determination at Heidrun and increased investments on mature fields, partly offset by decreased depreciation due to reduced production and increased proved reserves.

Exploration expenses were NOK 3.5 billion, NOK 5.1 billion and NOK 5.5 billion in 2012, 2011 and 2010, respectively. 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. The decrease from 2010 to 2011 was mainly due to lower exploration expenditures capitalised in previous years being expensed.

Net operating income in 2012 was NOK 161.7 billion, compared to NOK 152.7 billion in 2011 and NOK 115.6 billion in 2010. The NOK 9.0 billion increase in 2012 was mainly due to increased gas prices and lifted volumes of gas. The NOK 37.1 billion increase in 2011 was mainly due to increased liquid prices.

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.

In 2010, an unrealised gain on derivatives (NOK 2.1 billion), an adjustment related to pension and other provisions (NOK 0.9 billion), overlift (NOK 0.4 billion) and gain on sales of assets (NOK 0.4 billion) positively impacted net operating income, partly offset by a refund related to previous gas sales (NOK 0.1 billion).

4.1.5 DPI profit and loss analysis

In 2012, DPI delivered strong operational performance with significantly increased entitlement production, up 41%, averaging 470 mboe per day.

In 2012, DPI generated total revenues and other income of NOK 82.9 billion and a net operating income of NOK 21.5 billion.

Operational review

Operational data	For the year ended 31 December				
	2012	2011	2010	12-11 change	11-10 change
Prices					
Liquids price (USD/bbl)	**101.4**	105.7	76.8	(4%)	38%
Liquids price (NOK/bbl)	**590.3**	592.8	464.2	(0%)	28%
Production (mboe per day)					
Entitlement liquids	**342**	252	263	35%	(4%)
Entitlement natural gas	**128**	82	68	56%	20%
Total entitlement liquids and gas production	**470**	334	332	41%	1%
Total equity liquids and gas production	**669**	534	514	25%	4%
Liftings (mboe per day)					
Liquids liftings	**326**	237	258	38%	(8%)
Gas liftings	**128**	82	68	56%	20%
Total liquids and gas liftings	**454**	318	327	43%	(2%)

The average daily equity liquids and gas production (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 669 mboe in 2012, compared to 534 mboe in 2011 and 514 mboe in 2010. 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 increase of 4% from 2010 to 2011 was driven primarily by production start-up from Peregrino (Brazil) and Pazflor (Angola), partly offset of turnaround on Azeri, Chirag & Gunashli (ACG) in Azerbaijan and decline in production profiles in several fields in Angola.

The average daily entitlement production of liquids and gas (see section *Financial review - Operating and financial review - Definition of reported volumes*) was 470 mboe per day in 2012, compared to 334 mboe per day in 2011 and 332 mboe per day in 2010. The increase from 2011 to 2012 was driven by increased equity production as described above and a relatively lower negative effect from production sharing agreements.

From 2010 to 2011, the average daily entitlement production of liquids and gas increased slightly. Increased equity production of 4% as described above was offset by a relatively higher PSA effect in the period. The PSA effect was 199 mboe, 200 mboe and 182 mboe per day in 2012, 2011 and 2010, 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 2012	2011	2010	12-11 change	11-10 change
Total revenues and other income	**82.9**	70.9	51.0	17%	39%
Purchases [net of inventory variation]	**1.3**	0.7	0.0	91%	>100%
Operating expense and selling, general and administrative expenses	**19.3**	14.9	11.4	30%	30%
Depreciation, amortisation and net impairment losses	**26.2**	13.8	16.7	90%	(17%)
Exploration expenses	**14.6**	8.7	10.3	67%	(15%)
Total expenses	**61.4**	38.1	38.4	61%	(1%)
Net operating income	**21.5**	32.8	12.6	(35%)	>100%

DPI generated **total revenues and other income** of NOK 82.9 billion in 2012 compared to NOK 70.9 billion in 2011 and NOK 51.0 billion in 2010. 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, gain from sale 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 a gain from the sale of assets of NOK 14.2 billion in 2011.

The increase from 2010 to 2011 was mainly related to gains of NOK 14.2 billion from the sale of 40% ownership interests in Peregrino and Canadian oil sands assets and a 28% increase in realised liquid and gas prices measured in NOK, which had a positive impact of NOK 12.5 billion. The increase was partly offset by a 2% reduction in lifted volumes, which had a negative impact of NOK 3.0 billion and a net reduction in other income of NOK 3.8 billion.

Purchases [net of inventory variation] were NOK 1.3 billion in 2012, compared to NOK 0.7 billion in 2011 and NOK 0.0 billion in 2010. The increase from 2011 to 2012 was mainly related to diluent purchases for Leismer operations that started in January 2011. The same factor also explained the increase from 2010 to 2011.

Operating expenses and selling, general and administrative expenses were NOK 19.3 billion in 2012, compared to NOK 14.9 billion in 2011 and NOK 11.4 billion in 2010. The 30% increase from 2011 to 2012 was mainly due to increased royalty expenses of NOK 2.8 billion. In addition, higher production and ramp-up on several fields increased expenses. The 30% increase from 2010 to 2011 was mainly due to ramp-up of Marcellus and Eagle Ford in the US and production start-up of Peregrino in Brazil, Pazflor in Angola and Leismer in Canada in 2011.

Depreciation, amortisation and net impairment losses were NOK 26.2 billion in 2012, compared to NOK 13.8 in 2011 and NOK 16.7 billion in 2010. 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. The decrease from 2010 to 2011 was mainly due to a net reduction in impairments of NOK 3.6 billion based on a net impairment of NOK 1.5 billion in 2010 compared with a net impairment reversal of NOK 2.1 billion in 2011. In addition, ordinary depreciation increased by NOK 0.7 billion in 2011 compared to 2010, due to ramp up of Marcellus in the US and start-up on Peregrino in Brazil and Pazflor in Angola. The increase was partly offset by lower production and increased reserves in various other fields.

Exploration expenses were NOK 14.6 billion in 2012, compared to NOK 8.7 billion in 2011 and NOK 10.3 billion in 2010. The increase from 2011 to 2012 was primarily driven by increased expenses of non-commercial wells and increased seismic and field evaluation costs. Exploration expenses decreased by NOK 1.6 from 2010 to 2011, primarily due to increased capitalisation of exploration expenditures in 2011 compared to 2010.

Net operating income in 2012 was NOK 21.5 billion, compared to NOK 32.8 billion in 2011 and NOK 12.6 billion in 2010. 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. The increase from 2010 to 2011 was primarily attributable to a gain from the sale of the Peregrino and Canadian oil sands assets and increased liquids prices, partly offset by increased operating expenses and selling, general and administrative expenses.

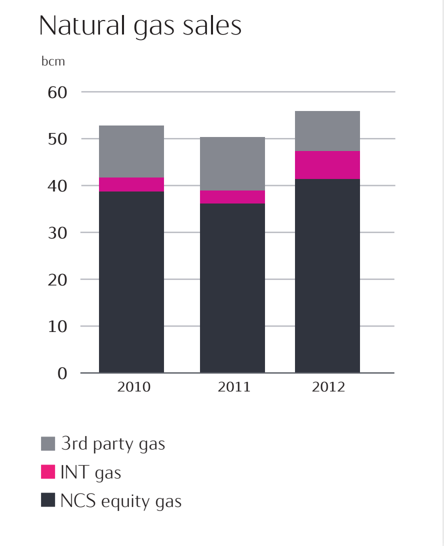
In 2012, net operating income was positively impacted by gain on sale of assets of NOK 1.0 billion and NOK 0.1 billion from a signature bonus reimbursement. In 2011, net operating income was positively impacted by NOK 14.2 billion from gains on sale of assets and net impairment reversals of NOK 2.4 billion. Over/underlift position of NOK 0.4 billion and NOK 0.1 billion in other adjustments negatively impacted net operating income. In 2010, an overlift of NOK 1.0 billion positively impacted net operating income, whereas impairment losses of NOK 2.1 billion (NOK 0.3 billion affecting exploration and NOK 1.8 billion affecting depreciation and amortisation) and decreased other income of NOK 0.2 billion, negatively impacted net operating income.

4.1.6 MPR profit and loss analysis

In 2012, MPR experienced higher margins on refining, increased sales and trading of oil and gas and also higher gas volumes sold.

Operational review

	For the year ended 31 December				
Operational data	2012	2011	2010	12-11 change	11-10 change
Refining reference margin (USD/bbl)	5.5	2.3	3.9	>100%	(41%)
Contract price methanol (EUR/tonne)	335	308	254	9%	21%
Natural gas sales Statoil entitlement (bcm)	47.3	39.0	41.7	22%	(7%)
Natural gas sales (third-party volumes) (bcm)	8.6	11.4	11.1	(25%)	3%
Natural gas sales (bcm)	55.9	50.4	52.8	11%	(5%)
Natural gas sales on commission	1.7	1.3	1.5	30%	(11%)
Average invoiced gas price (NOK/scm)	2.19	2.08	1.72	5%	21%
Transfer price natural gas (NOK/scm)	1.84	1.64	1.27	12%	29%

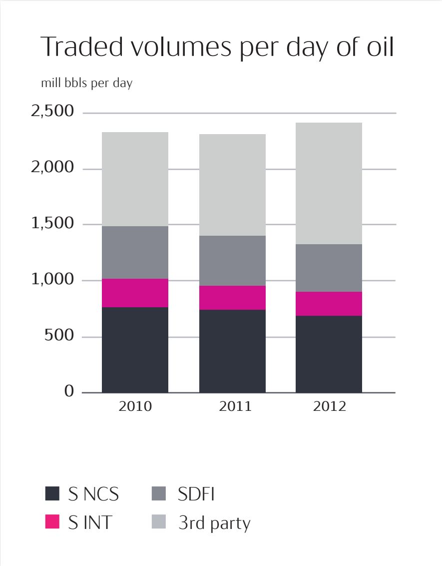


Total natural gas sales volumes were 55.9 bcm in 2012 (1.97 tcf), 50.4 bcm (1.78 tcf) in 2011 and 52.8 bcm (1.86 tcf) in 2010. The 11% increase in total gas volumes sold from 2011 to 2012 was mainly related to higher entitlement production. The 5% decrease in gas volumes sold from 2010 to 2011 was mainly related to lower entitlement production.

In addition, MPR sold 39.9 bcm, 33.5 bcm and 35.3 bcm of NCS gas on behalf of the Norwegian state's direct financial interest (SDFI) in 2012, 2011 and 2010, respectively.

In 2012, the average invoiced natural gas sales price was NOK 2.19 per scm, compared to NOK 2.08 per scm in 2011, an increase of 5%. The increase 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. The average invoiced natural gas sales price was NOK 1.72 per scm in 2010. The increase of 21% from 2010 to 2011 was due to an increase in gas price for contracts linked to oil products as well as gas indexed prices.

All of Statoil's gas produced on the NCS is sold by MPR, purchased from DPN at a market-based internal price. The increased natural gas sales prices in 2012 were largely offset by an increase in the internal purchase price. Our average internal purchase price for gas was NOK 1.84 per scm in 2012, up from NOK 1.64 per scm in 2011, an increase of 12%. The average internal purchase price for gas was NOK 1.27 per scm in 2010.

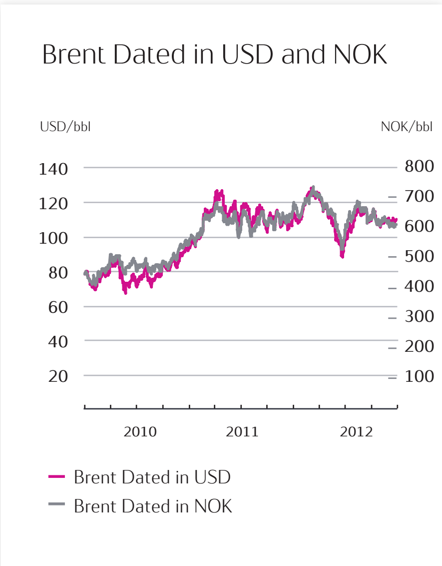


The average crude, condensate and NGL sales is 2.4 mmbbl per day in 2012. Of these daily sales, approximately 0.90 mmbbl are sales of our own volumes, 1.09 mmbbl are sales of third-party volumes and 0.43 mmbbl are sales of SDFI volumes. Our average sales volume was 2.3 mmbbl per day both in 2011 and in 2010. The average daily third-party volumes sold were 0.91 mmbbl in 2011 and 0.84 mmbbl in 2010.

The refinery margin improved significantly in 2012 in north-west Europe and the east coast of the US, especially during the second and third quarters. The increase was mainly driven by supply constraints due to refinery closures and maintenance. Statoil's refining reference margin was 5.5 USD/bbl in 2012, compared to 2.3 USD/bbl in 2011, an increase of 140%. The refining reference margin was 3.9 USD/bbl in 2010.

Financial review

Income statement under IFRS (in NOK billion)	For the year ended 31 December 2012	2011	2010	12-11 change	11-10 change
Total revenues and other income	**669.5**	610.0	493.6	10%	24%
Purchases [net of inventory variation]	**620.3**	550.5	452.1	13%	22%
Operating expense and selling, general and administrative expenses	**30.6**	28.8	29.3	6%	(2%)
Depreciation, amortisation and net impairment losses	**3.0**	6.0	6.0	(50%)	(0%)
Total expenses	**653.9**	585.2	487.5	12%	20%
Net operating income	**15.5**	24.7	6.1	(37%)	>100%



Total revenues and other income were NOK 669.5 billion in 2012, compared to NOK 610.0 billion in 2011 and NOK 493.6 billion in 2010. The increase in total revenues and other income 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%.

The increase from 2010 to 2011 was mainly due to higher prices for gas, crude and other oil products, increased volumes of crude sold and a gain related to the sale of the 24.1% interest in Gassled (NOK 8.4 billion). The increase was partly offset by reduced natural gas volumes sold. The average crude price in USD increased by approximately 40% in 2011 compared to 2010, partly offset by a weakening of the USD/NOK average daily exchange rate by almost 7%. The average invoiced sales price for gas increased by 21%. The increase was due to an increase in gas price for contracts linked to oil products as well as gas indexed prices. Total natural gas sales volumes decreased by 5%, mainly related to lower entitlement production in 2011.

Purchases [net of inventory variation] were NOK 620.3 billion in 2012, compared to NOK 550.5 billion in 2011 and NOK 452.1 billion in 2010. The increase from 2011 to 2012 was mainly due to higher prices and volumes for gas, crude and other oil products and gas sold. The increase from 2010 to 2011 was mainly due to higher prices for volumes purchased, partly offset by a weakening of the USD/NOK average daily exchange rate and lower transfer price for natural gas from DPN.

Operating expenses and selling, general and administration expenses were NOK 30.6 billion in 2012, compared to NOK 28.8 billion in 2011 and NOK 29.3 billion in 2010. The increase in expenses from 2011 to 2012 was mainly due to increased transport activity due to higher volumes of liquids and longer distances (to capitalise on market opportunities) and increased external gas transportation cost due to lower Gassled ownership, partly offset by lower Gassled tariffs. The decrease in expenses from 2010 to 2011 was mainly due to reversal of the onerous contract provision in connection with a re-gasification terminal in the USA (Cove Point), reduced Gassled transportation tariffs and asset removal obligation, partly offset by new time charter shipping contracts, increased transportation activity in the USA and operation of the new combined heat and power plant (CHP) at Mongstad.

Depreciation, amortisation and net impairment losses were NOK 3.0 billion in 2012, compared to NOK 6.0 billion in 2011 and NOK 6.0 billion in 2010. 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 15.5 billion, NOK 24.7 billion and NOK 6.1 billion in 2012, 2011 and 2010, respectively.

Net operating income in **Natural Gas processing, marketing and trading** (gas processing, transportation, sales and trading activities) was NOK 12.3 billion, NOK 27.5 billion and NOK 8.3 billion in 2012, 2011 and 2010, respectively.

The decrease 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.

The increase in net operating income in Natural Gas processing, marketing and trading of NOK 19.2 billion from 2010 to 2011 was mainly due to the gain related to the sale of the 24.1% interest in Gassled and reduced depreciation related to the Gassled interest sold, a large positive change in fair value derivatives (positive NOK 4.6 billion in 2011, compared to negative NOK 4.1 billion in 2010), reversal of provisions relating to an onerous contract accrued for in 2009 and 2010 (positive NOK 1.6 billion in 2011, compared to negative NOK 0.9 billion in 2010), and slightly higher margins on our gas sales due to higher prices. The positive changes were partly offset by the 3.7% reduction in ownership share in Gassled with effect from 1 January 2011 and lower entitlement volumes and impairment loss in 2011 related to a gas-fired power station (NOK 0.3 billion).

Net operating income in **Crude oil processing, marketing and trading** (oil sales and trading activities in addition to our refinery activities, the Tjeldbergodden Methanol plant, our three crude oil terminals and the midstream activities related to Eagle Ford and Bakken in the US) was NOK 3.5 billion, a loss of NOK 2.4 billion and a loss of 1.6 billion in 2012, 2011 and 2010, respectively.

The increase 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.

The increased loss in Crude oil processing, marketing and trading of NOK 0.8 billion from 2010 to 2011 was mainly due to lower margins from trading of crude oil, products and gas liquids and storage strategies in an unfavourable and challenging market, lower refining margins and higher impairment losses related our refinery assets (NOK 3.8 billion in 2011, compared to NOK 2.9 billion in 2010). The negative changes were partly offset by a positive change in fair value effects related to inventory hedging, a loss accrued for related to an onerous sales contract in 2010 (NOK 0.4 billion) and higher gain on operational storage in 2011 compared to in 2010.

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 Services.

In 2012, the Other reporting segment recorded a net operating income of NOK 2.6 billion compared to a net operating loss of NOK 0.3 billion in 2011 and net operating income of NOK 0.6 billion in 2010. The increase in net operating income from 2011 to 2012 was driven by a reversal of a provision related to the discontinued part of the early retirement pension. The decrease in net operating income from 2010 to 2011 was mainly driven by a gain from the sale of Tampnet, a communication network between offshore installations, to HitecVision in 2010.

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.

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 *30 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 delivered strong cash flows in 2012, mainly as a result of increased cash flows from operating activities and continued portfolio optimisation.

Condensed cash flow statement (in NOK billion)	For the year ended 31 December 2012	2011 (restated)	2010 (restated)	Change 12-11	Change 11-10
Income before tax	206.7	213.8	136.8	(7.1)	77.0
Adjustments to reconcile net income to net cash flows provided by operating activities:					
Depreciation, amortisation, impairment	60.5	51.4	50.7	9.2	0.7
Exploration expenditures written off	3.1	1.5	2.9	1.6	(1.4)
(Gains) losses on foreign currency transactions and balances	3.3	4.2	1.5	(0.9)	2.6
(Gains) losses on sales of assets other items	(21.7)	(27.7)	(1.1)	6.1	(26.6)
(Increase) decrease in net derivative financial instruments	(1.1)	(12.8)	(0.6)	11.6	(12.2)
Cash flows from (to) changes in working capital	4.6	1.9	(10.6)	2.7	12.5
Taxes paid	(119.9)	(112.6)	(92.3)	(7.4)	(20.3)
Other changes	(7.4)	(0.7)	(2.2)	(6.7)	1.5
Cash flows provided by operating activities	128.0	119.0	85.2	9.0	33.8
Additions to PP&E and intangible assets	(112.4)	(92.2)	(83.4)	(20.2)	(8.8)
Additions through business combinations	0.0	(25.7)	0.0	25.7	(25.7)
Proceeds from sales of assets and businesses	29.8	29.8	1.9	(0.0)	27.9
(Increase) decrease in financial investments	(12.1)	3.8	(2.8)	(15.9)	6.6
Other changes	(1.9)	(0.6)	5.0	(1.4)	(5.6)
Cash flows used in investing activities	(96.6)	(84.9)	(79.3)	(11.8)	(5.6)
Net change in long-term borrowing	0.9	2.7	12.2	(1.8)	(9.6)
Net current loans and other	1.6	4.5	5.9	(2.9)	(1.5)
Dividends paid	(20.7)	(19.9)	(19.1)	(0.8)	(0.8)
Cash flows provided by (used in) financing activities	(18.2)	(12.8)	(0.9)	(5.5)	(11.8)
Net increase (decrease) in cash and cash equivalents	13.2	21.4	5.0	(8.2)	16.4

Statoil has changed the 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 has been retrospectively applied and the table above shows the effect of the changes in previous periods. Refer to note 3 *Change in accounting policy* to the Consolidated financial statements for more details.

Cash flows provided by operations

For cash flows provided by operations, the major factors impacting changes between periods are our level of profitability, taxes paid and changes in working capital. The most significant drivers are the level of production and prices for liquids and natural gas that impact revenues, cost of purchases (net of inventory valuation), taxes paid and changes in working capital items. Cash flows provided by operations amounted to NOK 128.0 billion in 2012, an increase of NOK 9.0 billion compared to 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 other changes of NOK 6.7 billion.

Cash flows provided by operations amounted to NOK 119.0 billion in 2011, compared to NOK 85.2 billion in 2010. The increase was largely driven by increased profitability mainly caused by higher liquids and gas prices in 2011 compared to 2010, and positive changes in working capital, partially offset by higher taxes paid by NOK 20.3 billion.

Cash flows used in investing activities

Cash flows used in investing activities increased by NOK 11.8 billion from 2011 to 2012. The increase was mainly due to higher additions to PP&E and intangible assets of NOK 20.2 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. Proceeds from sales remained at the same level. 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 SFR. Proceeds from sales for the year ended 2011 were mainly related to the sale of interests in the Kai Kos Dehseh oil sands in Canada and the Peregrino oil field in Brazil.

In 2011, cash flows used in investing activities amounted to NOK 84.9 billion, an increase of NOK 5.6 billion from 2010. In 2011, Statoil acquired the shares in Brigham Exploration Company, resulting in an increase in additions through business combinations of NOK 25.7 billion. The increased investment activity in 2011 compared to 2010 contributed to an increase in additions to PP&E and intangible assets of NOK 8.8 billion. The increase in cash spent on investing activities was partly offset by proceeds from sales (NOK 29.8 billion), mainly related to proceeds from the sale of interests in the Kai Kos Dehseh oil sands in Canada and the Peregrino oil field in Brazil.

Cash flows provided by (used in) financing activities

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 long-term borrowing of NOK 1.8 billion and change in current loans and other of NOK 2.9 billion, mainly due to increased repayment of loans.

Net cash flows used in financing activities in 2011 amounted to NOK 12.8 billion, an increase of NOK 11.8 billion compared to 2010. The change was mainly related to a net decrease in long-term borrowing of NOK 9.6 billion due to fewer new bonds being issued in combination with a larger portion of repayment of bonds in 2011 compared to 2010.

4.2.2 Financial assets and liabilities

Statoil has a strong balance sheet and financial flexibility. The net debt ratio before adjustments was 10.9% in 2012 and net interest-bearing financial liabilities decreased by NOK 31.7 billion to NOK 39.3 billion at the end of 2012.

Financial condition and liquidity

Statoil's financial position is strong, and we have financial flexibility. Statoil has reduced net debt ratio before adjustments from 23.5% in 2010 to 10.9% in 2012. Net interest-bearing liabilities have decreased from NOK 69.5 billion as of 31 December 2010 to NOK 39.3 billion as of 31 December 2012. At the same time, Statoil's total equity has increased from NOK 226.4 billion to NOK 319.9 billion.

The reduction in net interest-bearing liabilities is due to, among others, robust operating cash flow and active portfolio management (proceeds from sales of assets and businesses). At the same time Statoil has continued its investment activities and provided attractive capital distribution to the shareholders. We paid a dividend of NOK 6.50 for 2011, and the board of directors has proposed a dividend of NOK 6.75 per share for 2012.

We believe that, given Statoil's established liquidity reserves (including committed credit facilities) and Statoil's credit rating and access to capital markets, Statoil has sufficient working capital for its foreseeable requirements.

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 to have access at all times to a variety of funding sources, in respect of both instruments and geography, and to maintain relationships with a core group of international banks that provide various kinds of banking and funding services.

We have credit ratings from Moody's and Standard & Poor's (S&P), and the stated objective is to have a rating at least within the single A category on a stand-alone basis. This rating ensures necessary predictability when it comes to funding access on attractive terms and conditions. Our current long-term ratings are Aa2 stable outlook and AA- stable outlook from Moody's and Standard & Poor's, respectively. The short-term rating from Moody's is P-1 and A-1+ from Standard & Poor's. We intend to keep financial ratios relating to our cash flows from operating activities and debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category on a stand-alone basis in order to sustain financial flexibility going forward. In this context, we carry out different 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 take into consideration funding sources, the maturity profile of non-current bonds, interest rate risk management, currency risk and the management of liquid assets. Our borrowings are denominated in various currencies and swapped into USD, since the largest proportion of our net cash flow is denominated in 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 finance function 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 2012, approximately 46% of our liquid assets were held in NOK-denominated assets, 31% in USD, 11% in GBP, 8% in DKK and 4% in EUR, before the effect of currency swaps and forward contracts. Approximately 57% of our liquid assets were held in treasury bills and commercial papers, 27% in time deposits, 10% at bank available, 3% in liquidity funds and 1% in bonds. As of 31 December 2012, approximately 2% of our liquid assets were classified as restricted cash (including collateral deposits).

Our general policy is to maintain a liquidity reserve in the form of cash and cash equivalents 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 and cash flows and when market conditions are considered favourable.

The group's borrowing needs are mainly covered through the issuing of short-term and long-term securities, including utilisation of a US Commercial Paper Program and a Euro Medium-Term Note (EMTN) Programme (program limits being USD 4.0 billion and USD 8.0 billion, respectively) as well as issues under a US Shelf Registration Statement, and through draw-downs under committed credit facilities and credit lines. After the effect of currency swaps, 100% of our borrowings are in USD.

- The USD 3.0 billion multi-currency revolving credit facility that Statoil ASA, guaranteed by Statoil Petroleum AS, has available from a group of 20 international banks, had its term extended by one year until December 2017. Up to one-third of the facility may be utilised in the form of swing line advances, i.e. drawdowns available on a same-day notice and with maximum maturities of ten days.
- Statoil ASA issued new debt securities in 2012 in the amounts of USD 0.6 billion maturing in January 2018 and 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 of NOK 11.6 billion). The registered bonds were issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the Securities and Exchange Commission (SEC) in the United States. All of the bonds are guaranteed by Statoil Petroleum AS.
- Statoil ASA issued new debt securities in 2011 in the amount of USD 0.65 billion maturing in November 2016, USD 0.75 billion maturing in January 2022 and USD 0.35 billion maturing in November 2041 (an aggregate amount of NOK 10.1 billion). The registered bonds were issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the Securities and Exchange Commission (SEC) in the United States. All of the bonds are guaranteed by Statoil Petroleum AS.

Financial indicators

Financial indicators (in NOK billion)	For the year ended 31 December 2012	2011 (restated)	2010 (restated)
Gross interest-bearing financial liabilities (1)	119.4	131.5	111.5
Net interest-bearing liabilities before adjustments	39.3	71.0	69.5
Net debt to capital employed ratio (2)	10.9%	19.9%	23.5%
Net debt to capital employed ratio adjusted (3)	12.4%	21.1%	25.5%
Cash and cash equivalents	65.2	55.3	33.8
Current financial investments	14.9	5.2	8.2
Calculated ROACE based on Average Capital Employed before Adjustments (4)	18.7%	22.1%	12.6%
Ratio of earnings to fixed charges (5)	19.6	35.2	18.2

Gross interest-bearing financial liabilities

Gross interest-bearing financial liabilities were NOK 119.4 billion, NOK 131.5 billion and NOK 111.5 billion at 31 December 2012, 2011 and 2010, respectively. The NOK 12.1 billion decrease from 2011 to 2012 was due to a decrease in current *Bonds, bank loans, commercial papers and collateral liabilities* of NOK 1.4 billion and non-current *Bonds, bank loans and finance lease liabilities* of NOK 10.7 billion. Our weighted average annual interest rate was 4.74%, 4.84% and 5.01% at 31 December 2012, 2011 and 2010, respectively. Our weighted average maturity on bonds, bank loans and finance lease liabilities was 9 years at 31 December 2012, 2011 and 2010.

The NOK 20.0 billion increase from 2010 to 2011 was mainly due to an increase in non-current *Bonds, bank loans and finance lease liabilities* of NOK 11.8 billion, including a financial lease of NOK 4.9 billion related to Statoil's share of the Peregrino FPSO vessel that was reclassified from held for sale to non-current *Bonds, bank loans and finance lease liabilities*, and an increase in current *Bonds, bank loans, commercial papers and collateral liabilities* of NOK 8.2 billion.

Net interest-bearing financial liabilities

Net interest-bearing financial liabilities before adjustments were NOK 39.3 billion, NOK 71.0 billion and NOK 69.5 billion at 31 December 2012, 2011 and 2010, respectively. The decrease of NOK 31.7 billion from 2011 to 2012 was mainly related to a decrease in gross interest-bearing financial liabilities of NOK 12.1 billion in addition to an increase in cash and cash equivalents and current financial investments of NOK 19.7 billion, reflecting increased operating cash flow and active portfolio management (proceeds from sales of assets and businesses).

The net debt to capital employed ratio

The net debt to capital employed ratio before adjustments was 10.9%, 19.9% and 23.5% in 2012, 2011 and 2010, respectively.

The net debt to capital employed ratio adjusted (non-GAAP financial measure, see footnote 3) was 12.4%, 21.1% and 25.5% in 2012, 2011 and 2010, respectively. 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 financial liabilities adjusted of NOK 30.9 billion in combination with an increase in capital employed adjusted of NOK 3.8 billion. The 4.4 percentage points decrease from 2010 to 2011 was mainly related to a decrease in net interest bearing financial liabilities adjusted of NOK 1.4 billion in combination with an increase in capital employed adjusted of NOK 57.4 billion.

Cash, cash equivalents and current financial investments

Cash and cash equivalents were NOK 65.2 billion, NOK 55.3 billion and NOK 33.8 billion at 31 December 2012, 2011 and 2010, respectively. The increase from 2010 to 2012 reflects the increased cash flow from operations in the period, in combination with proceeds from sales of assets and businesses. See note 18 *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 14.9 billion, NOK 5.2 billion and NOK 8.2 billion at 31 December 2012, 2011 and 2010, respectively.

(1) Defined as non-current and current bonds, bank loans and finance lease liabilities.
(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.
(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 18.0 billion for the year ended 31 December 2012, in line with our guidance for 2012 of around USD 18 billion.

Capital expenditures

Gross investments (in NOK billion)	For the year ended 31 December 2012	2011	2010	12-11 Change	11-10 Change
- Development & Production Norway	**48.6**	41.4	31.9	17%	30%
- Development & Production International	**54.6**	84.4	40.4	(35%)	>100%
- Marketing, Processing & Renewable Energy	**6.2**	4.6	6.3	34%	(27%)
- Fuel & Retail	**0.9**	1.5	0.8	(41%)	85%
- Other	**3.0**	1.6	4.9	85%	(67%)
Gross investments	**113.3**	133.6	84.4	(15%)	58%

Gross investments (defined as additions to property, plant and equipment (including capitalised financial lease), capitalised exploration expenditure, intangible assets, long-term share investments and non-current loans granted) amounted to NOK 113.3 billion for the year ended 2012, down NOK 20.3 billion compared to the year ended 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.

In 2011, gross investments were NOK 133.6 billion compared to NOK 84.4 billion in 2010, reflecting the acquisition of Brigham Exploration Company for NOK 25.7 billion and increased activity level in 2011 compared to 2010.

Organic capital expenditures (excluding acquisitions and financial leases) amounted to NOK 108.1 billion for the year ended 2012, or USD 18.0 billion based on a normalised exchange rate of 6 NOK/USD. This is in line with our guidance for 2012 of around USD 18 billion. Organic capital expenditures are estimated to be around USD 19 billion in 2013.

This section describes our estimated organic capital expenditure for 2013 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 operational 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 2013 capital expenditures will be spent on ongoing and planned development projects in Norway such as Gudrun, Goliat, Valemon and Aasta Hansteen 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 2013 capital expenditure will be spent on the following ongoing and planned development projects internationally: CLOV in Angola, Mariner in UK, Peregrino in Brazil, Shah Deniz in Azerbaijan, Marcellus, Eagle Ford and Bakken onshore US, and developments offshore US.

We currently estimate that most of the 2013 capital expenditures spent on midstream and downstream projects will be related to 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 2012 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

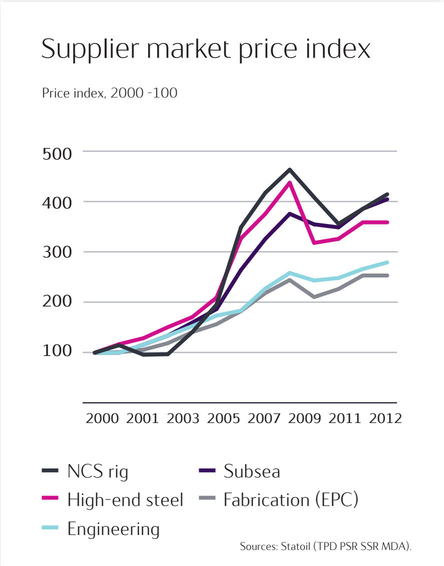
Exploration expenditures in 2012 amounted to NOK 20.9 billion, compared to NOK 18.8 billion in 2011 and NOK 16.8 billion in 2010. Exploration expenditure in 2013 is expected to remain at approximately the same level as in 2012, estimated to be around USD 3.5 billion for 2013. The group expects to participate in the drilling of approximately 50 wells in 2013. 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.

Stabilisation of raw material prices has dampened the total increase in 2012, although raw material prices have stayed at an overall high level. As in previous years, price increases were seen in the rig, subsea and engineering segments in 2012.



Although price pressure has abated since it peaked in 2008 (3.8%), our results have been significantly affected in the last few years by inflation in the cost of certain raw materials and services that are necessary for the development and operation of oil- and gas-producing assets. Other parts of our business are not exposed to similar cost pressures.

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*.

As measured by the general consumer price index, average annual inflation in Norway for the years ended 31 December 2012, 2011, 2010 and 2009 was 0.8%, 1.2%, 2.5% and 2.1%, respectively.

4.2.5 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2012.

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 2012 Payment due by period *				
	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Undiscounted non-current financial liabilities	10.2	26.4	20.1	93.3	149.9
Minimum operating lease payments	22.7	37.2	20.0	29.9	109.8
Nominal minimum other long-term commitments**	14.4	25.6	25.4	102.1	167.5
Total contractual obligations	47.3	89.2	65.5	225.3	427.2

* «Less than 1 year» represents 2013; «1-3 years» represents 2014 and 2015, «3-5 years» represents 2016 and 2017, while «More than 5 years» includes amounts for later periods.

** For further information, see note 26 *Other commitments and contingencies* to the Consolidated financial statements.

Non-current financial liabilities in the table represent principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 20 *Bonds, bank loans and finance lease liabilities* and note 25 *Leases* to the Consolidated financial statements.

Contractual commitments relating to capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 53 billion as of 31 December 2012.

The group's projected pension benefit obligation was NOK 68.7 billion, and the fair value of plan assets amounted to NOK 57.5 billion as of 31 December 2012. 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 25 *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 26 *Other commitments and contingencies* to the Consolidated financial statements for more information.

4.3 Accounting Standards (IFRS)

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

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

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

4.4 Non-GAAP measures

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

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

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

- Return on average capital employed (ROACE)
- 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 18.7% in 2012 compared to 22.1% in 2011 and 12.6% in 2010. The decrease from last year is due to the decrease in net income combined with a 10% increase in capital employed. The increase from 2010 to 2011 was due to doubling of net income adjusted for financial items after tax, slightly offset by a 15% increase in capital employed.

Calculation of numerator and denominator used in ROACE calculation	For the year ended 31 December				
(in NOK billion, except percentages)	2012	2011	2010	12-11 Change	11-10 Change
Net Income for the year	69.5	78.4	37.6	(11%)	>100%
Net Financial Items Adjusted for the year	(2.3)	(8.2)	(2.5)	(71%)	>100%
Calculated Tax on Financial Items for the year 1)	(0.1)	1.6	0.7	>(100%)	>100%
Net Income adjusted for Financial Items after Tax (A1)	67.0	71.9	35.8	(7%)	>100%
Capital Employed before Adjustments to Net Interest-bearing Debt: 2)					
Year end 2012	359.2				
Year end 2011	356.1	356.1			
Year end 2010		295.9	295.9		
Year end 2009			271.9		
Sum of Capital Employed for two years (B1)	715.3	652.0	567.8		
Calculated Average Capital Employed:					
Average Capital Employed before Adjustments to Net Interest-bearing Debt (B1/2)	357.7	326.0	283.9	10%	15%
Calculated RoACE:					
Return on Average Capital Employed (A1/(B1/2))	18.7%	22.1%	12.6%	(15%)	75%

1) 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.
2) 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 have on entitlement volumes (PSA effects), 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 2012	2011	2010
Operating expenses, Statoil Group	64.0	60.4	57.5
Deductions of costs not relevant to production cost calculation			
Operating expenses in Business Areas non-upstream	22.2	24.5	25.5
Total operating expenses upstream	41.7	35.9	32.0
1) Operation over/underlift	(0.2)	(1.2)	0.8
2) Transportation pipeline/vessel upstream	5.9	5.2	4.4
3) Miscellaneous items	5.0	3.3	0.5
4) Total operating expenses upstream for cost per barrel calculation	31.0	28.6	26.3
Entitlement production used in the cost per barrel calculation (mboe/d)	1,805	1,650	1,705
Equity production used in the cost per barrel calculation (mboe/d)	2,004	1,850	1,888

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 21 *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.

	Entitlement production For the year ended 31 December			Equity production For the year ended 31 December		
Production cost (in NOK per boe)*	2012	2011	2010	2012	2011	2010
Production cost per boe	47	47	42	42	42	38

* 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 by 199 mboe per day in 2012, 200 mboe per day in 2011 and 182 mboe per day in 2010. 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 42 per boe in 2012 compared to NOK 42 per boe in 2011 and NOK 38 per boe in 2010.

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)	For the year ended 31 December 2012	2011 (restated)	2010 (restated)
Shareholders' equity	319.2	278.9	219.5
Non-controlling interests (Minority interest)	0.7	6.3	6.9
Total equity (A)	319.9	285.2	226.4
Current bonds, bank loans, commercial papers and collateral liabilities	18.4	19.8	11.7
Bonds, bank loans and finance lease liabilities	101.0	111.6	99.8
Gross interest-bearing financial liabilities (B)	119.4	131.5	111.5
Cash and cash equivalents	65.2	55.3	33.8
Financial investments	14.9	5.2	8.2
Cash and cash equivalents and financial investments (C)	80.1	60.5	42.0
Net interest-bearing liabilities before adjustments (B1) (B-C)	39.3	71.0	69.5
Other interest-bearing elements (1)	7.3	6.9	9.9
Marketing instruction adjustment (2)	(1.2)	(1.4)	(1.5)
Adjustment for project loan (3)	(0.3)	(0.4)	(0.6)
Net interest-bearing liabilities adjusted (B2)	45.1	76.0	77.4
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing liabilities (A+B1)	359.2	356.1	295.9
Capital employed adjusted (A+B2)	365.0	361.2	303.8
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1)	10.9%	19.9%	23.5%
Net debt to capital employed adjusted (B2/(A+B2)	12.4%	21.1%	25.5%

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 liabilities due to the SDFI part of the financial lease in the Snøhvit vessels that are included in Statoil's balance sheet.
3) Adjustment for project loan is adjustment to gross interest bearing financial liabilities due to the BTC project loan structure.

5 Risk review

Our overall risk management approach 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 - such as oil prices, operational risks, competition and international relations.

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:

- global and regional 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 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. We are exploring or considering exploring in various geographical areas, including the Norwegian Sea, the Barents Sea and onshore and offshore in the USA. In some of these regions, environmental conditions are challenging and costs can be high. In addition, our use of advanced technologies requires greater pre-drilling expenditure than traditional drilling strategies. The costs of drilling, completing and operating wells are often uncertain. As a result, we may experience cost overruns or may be required to curtail, delay or cancel drilling operations due to a variety of factors, including equipment failures, changes in government requirements, unexpected drilling conditions, pressure or irregularities in geological formations, adverse weather conditions and shortages of, or delays in, the availability of drilling rigs and the delivery of equipment.

For example, we may enter into long-term leases for drilling rigs that may turn out not to be required for the operations for which they were originally intended, and we cannot be certain that these rigs will be re-employed or at what rates they will be re-employed. Fluctuations in the market for leases of drilling rigs will have an impact on the rates we can charge for re-employing these rigs. Our overall drilling activity or drilling activity within a particular project area may be unsuccessful. Such factors could have a material adverse effect on the results of our operations and financial condition.

We are exposed to a wide range of health, safety, security 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, among other things, in oil spills, gas leaks, loss of containment of hazardous materials, water fracturing, blowouts, cratering, fires, equipment failure and loss of well control. 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 by 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, could represent a significant risk to people and the environment. Offshore operations are subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions, as well as interruptions, restrictions or termination by government authorities based on safety, environmental or other considerations. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems or breaches of our security system could 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 material adverse effect on our operations or financial condition.

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.

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 the results of our operations and financial condition.

We encounter competition from other oil and natural gas companies in all areas of our operations, including the acquisition of licences, exploratory prospects and producing properties.
The oil and gas industry is extremely competitive, especially with regard to exploration for - and the exploitation and development of - new sources of oil and natural gas.

Some of our competitors are much larger, well-established companies with substantially greater resources. In many instances, they have been engaged in the oil and gas business for much longer than we have. These larger companies are developing strong market power through a combination of different factors, including:

- diversification and the reduction of risk;
- the financial strength necessary for capital-intensive developments;
- exploitation of benefits of integration;
- exploitation of economies of scale in technology and organisation;
- exploitation of advantages in terms of expertise, industrial infrastructure and reserves; and
- strengthening their positions as global players.

These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licences. They may also be able to invest more in developing technology than our financial or human resources permit. Our performance could be impeded if competitors were to develop or acquire intellectual property rights to technology that we require or if our innovation were to lag behind the industry. For more information on the competitive environment, see the section *Business overview - Our competitive position*.

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 hostile environments - such as the Gulf of Mexico, the Barents Sea, 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.

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

We may not be able to produce some of our oil and gas economically due to the lack of necessary 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 usually transported by tankers 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.

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 unstable regions around the world, including North Africa and the Middle East, where potential developments such as war, terrorism, 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 and control. Hostile actions against our staff, our facilities (as at the In Amenas joint venture in Algeria), 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 material adverse effect on the results of our operations and our financial condition.

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. We expect this trend to continue. 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 not predictable. If such risks materialise, they could cause us to incur material costs and/or cause our production to decrease, potentially having a material adverse effect on our operations or financial condition.

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 estimated capital expenditure for the offshore development of South Pars phases 6, 7 and 8 was USD 746 million in total. Final settlement with Petropars on the sharing of parts of the capital expenditures may lead to an adjustment of the amount of Statoil's final investment. 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 license expired in November 2010.

In connection with our decision to close down our project activities in Iran, we initiated cost recovery programmes in respect of our investments and settled our remaining contractual obligations. As of 31 December 2012, the cost recovery programme relating to South Pars phases 6, 7 and 8 and the Anaran Block has been completed, except for the recovery of taxes and the obligation to the Social Security Organization (SSO). Statoil agreed to settle its remaining minimum obligations under the Khorramabad exploration and development contract, and the settlement amount was offset against the cost recovery in respect of the Anaran Block. The Statoil office in Iran, in parallel with the progress of its cost recovery efforts, was further scaled down in 2012.

Statoil is not involved in any other activities in Iran. Statoil will not make any 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 Statoil was eligible to avoid sanctions under the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010 (CISADA) relating to its activities in Iran because Statoil had pledged to end its investments in Iran's energy sector.

Since 2010, additional and strengthened international (UN, US, EU and Norwegian) sanctions against Iran have been adopted. Over this 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 approved applications for specific transactions. Additional international sanctions against Iran may be imposed in the future.

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.

Our activities in Cuba during 2012 consisted of a 30% interest in six deepwater exploration blocks acquired from the operator Repsol-YPF in 2006. As of 31 December 2012, we had invested USD 147 million in these projects. However, the exploration licence expired in September 2012. Statoil prequalified to become an operator in Cuba in the first quarter of 2011. We were not awarded any new licences in Cuba in 2012.

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.

The economic challenges in Europe may affect our business.
The European gas market is currently our most significant market for gas sales. The Eurozone continues to face economic challenges and risks of new setbacks remain. A prolonged recession would increase downward pressure on gas demand and prices in Europe, which would have a negative impact on the results of our operations and overall financial condition.

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. Combined with the stagnant economy and reduced demand for energy, the growth in the renewable energy sector has led to reduced demand for natural gas and increased volatility in power prices, particularly in Europe.

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. Shifts in government policy toward renewable energy, or wind power in particular, could lead us to modify our strategy in the renewable energy sector.

We may fail to attract and retain senior management and skilled personnel.
The attraction and retention of senior management and skilled personnel is a critical factor in the successful implementation of our strategy as an international oil and gas group. We may not always be successful in hiring or retaining suitable senior management and skilled personnel. Failure to recruit or retain senior management and skilled personnel or to more generally maintain good employee relations could compromise the achievement of our strategy. Such failure could cause disruption to our management structure and relationships, an increase in costs associated with staff replacement, lost business relationships or reputational damage. An inability to attract or retain suitable employees could have a significant adverse impact on our ability to operate.

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 affect on our liquidity and results of operations.

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.

In light of the incident at the BP-operated Macondo well in the Gulf of Mexico, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable.

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*.

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 significant 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 our ethical and social standards could harm 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 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.

5.1.2 Iran-related activity

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 Phase 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 obligations under these agreements have terminated and the licenses have been abandoned.

Statoil's remaining activity in Iran during 2012 was limited to cost recovery efforts in connection with its previous activity, including tax and Social Security Organization (SSO) settlements.

The cost recovery program for these contracts was completed in 2012, except for the recovery of tax and SSO. The Statoil office in Iran, in parallel with the progress of its cost recovery efforts, was further scaled down during 2012. Statoil received USD 220 million in remaining cost recovery for the South Pars field during 2012, booked as gross revenue from sales, USD 108 million in net cost recovery after deduction of taxes owed to Iran, depreciation and expenses. A portion of Statoil's investment in South Pars was impaired in previous years. Statoil received USD 194 million in remaining remuneration fee and cost recovery for previous exploration expenditures on the Anaran Block, booked as other income. The net recovery in relation to the Anaran Block after deduction of expenses and taxes owed to Norway and Iran amounts to USD 139 million. The Anaran Block cost recovery includes an offset equal to Statoil's uncompleted minimum work obligations on the Khorramabad Block.

Since 2009, including during its cost recovery efforts, Statoil has been transparent 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.

5.1.3 Legal and regulatory risks

This section discusses potential legal and regulatory risks related to the legal context of our business operations, such as having to comply with new laws and regulations.

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase 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 licences 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 licence 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 (such as the offshore safety regulation proposed by the European Commission on 27 October 2011, if such regulation is adopted by the European Economic Area), the imposition of stricter requirements on licences, increasingly strict enforcement of or new interpretations of existing laws and regulations, the aftermath of operational catastrophes in which 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, following the final report from US National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling of 11 January 2011. Additional changes in permitting or regulation 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.

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. In order to reach the goals set out in the directive, the European Commission proposes to separate production and supply from transmission networks, to facilitate cross-border trade in energy, stronger powers and independence for national regulators, to promote cross-border collaboration and investment, greater market transparency in network operation and supply, and increased solidarity among the EU countries.

Most of our gas is sold under long-term gas contracts to customers in the EU, a gas market that will continue to be affected by changes in EU regulations and the implementation of such regulations in EU member states. The general liberalisation of EU gas markets could affect our ability to expand or even maintain our current market position or result in a reduction in prices in our gas sales contracts.

Directive 2003/55/EC sets forth the right of third parties to non-discriminatory access to networks and to LNG and gas storage facilities. Increased access to markets has a downside insofar as it increases network access for all market participants and, thereby, competition for capacity at interconnection points within the EU. This may result in upward pressure on the price we pay for capacity at those points.

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.

A further focus area of EU energy policy is supply security, which has led to increased focus on projects that diversify gas supplies to the EU. As a result, the Caspian region, where Statoil is participating in the Shah Deniz field, has received increasing attention from the EU. Solutions aimed at bringing Caspian gas to Europe continue to receive political support from the EU in an attempt to resolve the complex transportation issue in the region.

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 extensive powers over 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 materially and adversely affected. For more information about the Norwegian State's regulatory powers, see the section *Business overview - Applicable laws and regulations*.

5.1.4 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.

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 11 March 2013. 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. Accordingly, when making commercial decisions relating to the NCS, we have to take the Norwegian State's coordinated ownership strategy into account, and we may not be able to fully pursue our own commercial interests, including those relating to our strategy for the development, production and marketing of oil and gas.

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 Norwegian State's coordinated ownership strategy, see the section *Business overview - Applicable* laws and regulations - The Norwegian State's participation.

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.

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 manage risk in order to ensure safe operations and to reach our corporate goals in compliance with our requirements.

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, defining and developing our risk policies. The committee meets at least six times a year to decide 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.

5.2.1 Managing financial risk

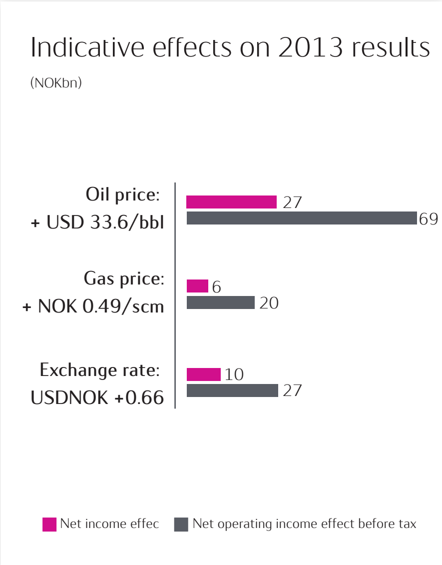
The results of our operations depend on a number of factors, most significantly those that affect the price we receive in Norwegian kroner (NOK) for our products.

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 USD/NOK exchange rates for 2012, 2011 and 2010.

Yearly average	2012	2011	2010
Crude oil (USD/bbl Brent blend)	111.5	111.4	76.5
Average invoiced gas price (NOK/scm)	2.2	2.1	1.7
Refining reference margin (USD/bbl)	5.5	2.3	3.9
USDNOK average daily exchange rate	5.8	5.6	6.1



The illustration shows the indicative full-year effect on the financial result for 2013 given certain changes in the crude oil price, natural gas contract prices and the USD/NOK 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 6 to the Consolidated financial statements, *Financial risk management,* for a discussion of financial risk management.

5.2.2 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 28 to the Consolidated financial statements, *Financial instruments: fair value measurement and sensitivity analysis of market risk*, 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.

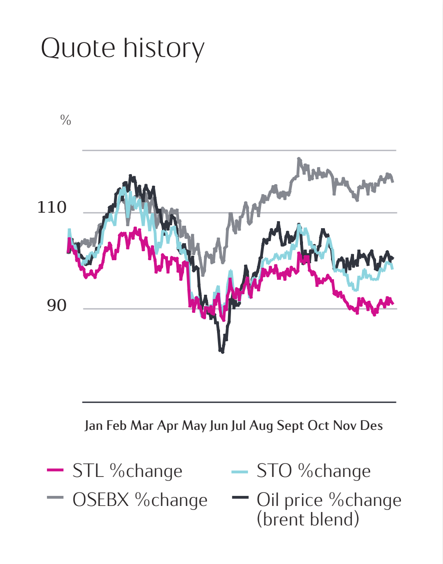
We are currently not aware of any legal proceedings or claims that we believe may have, or have had in the recent past, individually or in the aggregate, significant effects on our financial position or profitability or on the results of our operations or liquidity.

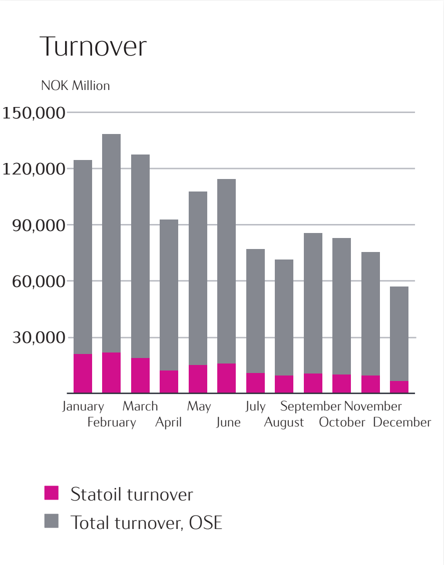
6 Shareholder information

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	2012	2011	2010	2009	2008
Share price STL (high) (NOK)	162.40	160.50	149.20	146.80	214.10
Share price STL (low) (NOK)	133.80	113.70	117.60	108.90	96.40
Share price STL (average) (NOK)	146.97	139.60	131.80	129.50	153.60
Share price STL year-end (NOK)	139.00	153.50	138.60	144.80	113.90
Market value-year end (NOK billion)	443	490	442	462	363
Daily turnover (million shares)	4.3	8.9	9.7	9.6	13.5
Ordinary and diluted earnings per share (EPS)(NOK)	21.60	24.70	11.94	5.74	13.58
P/E [1]	6.44	6.20	11.61	25.18	8.39
Total dividend per share (NOK) [2]	6.75	6.50	6.25	6.00	7.25
Ordinary dividend per share (NOK) [2]	6.75	6.50	6.25	6.00	4.40
Special dividend per share (NOK) [2]	0.00	0.00	0.00	0.00	2.85
Growth in ordinary dividend per share [3]	3.8%	4.0%	4.2%	36.4%	4.8%
Growth in total dividend per share	3.8%	4.0%	4.2%	(17.2%)	(14.7%)
Total dividend per share (USD) [4]	1.21	1.08	1.07	1.04	1.26
Pay-out ratio [5]	31%	26%	52%	104%	53%
Dividend yield [6]	4.9%	4.2%	4.5%	4.1%	6.4%
Ordinary shares outsanding, weighted average	3,181,546,060	3,182,112,843	3,182,574,787	3,183,873,643	3,185,953,538
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 2012.
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.





As of 31 December 2012, Statoil represented 28.3% of the total value of all companies registered on the Oslo stock exchange, with a market value of NOK 443.2 billion.

Statoil's share price closed at NOK 139.00 at the end of 2012.

Taking into consideration the dividend of NOK 6.50 per share paid in 2012, the total return was NOK -8 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 6.75 per share for 2012, for approval by the annual general meeting on 14 May 2013. The dividend of NOK 6.75 per share that it is proposed to distribute to our shareholders is equivalent to a direct yield of approximately 4.9%, and it represents 31% of our net income from 2012. Diluted earnings per share amounted to NOK 21.60, a decrease of 12.6% compared to 2011.

The turnover of shares is a measure of traded volumes. On average, 4.3 million Statoil shares were traded on the Oslo stock exchange every day in 2012 compared to 8.9 million shares in 2011. In 2012, Statoil shares accounted for 16% of the total market value traded throughout the year (see illustration), compared to 21% in 2011.

Statoil ASA has one class of shares, and each share confers one vote at the general meeting. Statoil ASA had 3,188,647,103 ordinary shares outstanding at year end.

As of 31 December 2012, Statoil had 99,845 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 100,589 shareholders at 31 December 2011.

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.

When deciding the annual dividend level, the board of directors will take into consideration expected cash flows, capital expenditure plans, financing requirements and needs for appropriate financial flexibility. In addition to the cash dividend, Statoil may buy back shares as part of its total distribution of capital to shareholders. There has been no change in the dividend policy since it was introduced in February 2010.

6.1.1 Dividends

Dividends for a fiscal year are declared at our annual general meeting the following year. The Norwegian Public Limited Companies Act forms the legal framework for dividend payments.

Under this act, dividends may only be paid in respect of a financial period for which audited financial statements have been approved by the annual general meeting of shareholders, and any proposal to pay a dividend must be recommended by the board of directors, accepted by the corporate assembly and approved by the shareholders at a general meeting. The shareholders at the annual general meeting may vote to reduce, but may not increase, the dividend proposed by the board of directors.

We can only distribute dividends (1) if our equity, based on Statoil ASA's unconsolidated balance sheet, amounts to 10% or more of the total assets reflected in our unconsolidated balance sheet without following the same creditor notice procedure as required for reducing the share capital, (2) to an extent that is compatible with good and careful business practice with due regard to any losses that we may have incurred since the last balance sheet date or that we may expect to incur, and (3) provided that the dividend to be distributed is calculated on the basis of our unconsolidated financial statements.

Although we currently intend to pay annual dividends on our ordinary shares, we cannot assure that dividends will be paid or 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 2007 on a per share basis and in aggregate, as well as the cash dividend proposed by our board of directors to be paid in 2013 on our ordinary shares for the fiscal year 2012.

Fiscal Year	Ordinary dividend per share NOK	Special dividend per share NOK	Total dividend per share NOK	Total NOK billion
2007	4.20	4.30	8.50	27.1
2008	4.40	2.85	7.25	23.1
2009	6.00		6.00	19.1
2010	6.25		6.25	19.9
2011	6.50		6.50	20.7
2012	6.75*		6.75*	21.5

* Proposed

In 2007 and 2008, the total dividend per share consisted of an ordinary dividend and a special dividend. Since 2009 the dividend per share has consisted of an ordinary dividend only. The proposed dividend per share for 2012 is an ordinary dividend only.

The proposed dividend for 2012 will be considered at the annual general meeting on 14 May 2013. The Statoil share will be traded ex-dividend from 15 May 2013, and, if approved, the dividend will be disbursed on 29 May 2013. For US ADR holders, the ex-dividend date will be 17 May 2013.

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 29 May 2013. 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 prevailing bank charges. The payment date for dividend in USD to US ADR holders is expected to be 5 June 2013.

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 2012-2013, the board of directors was authorised by the annual general meeting of Statoil to repurchase Statoil shares in the market for subsequent annulment. We did not undertake any share repurchases in the market in 2012 or 2011.

Future share repurchases will depend on authorisation by our shareholders, as well as a number of factors prevailing at the time our board of directors considers any share repurchase.

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 2012.

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 employee contribution to 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. Shares transferred to employees are acquired by the company in the market.

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 27,500,000. 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 2013. 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 19 May 2011.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 27,500,000, 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 [1]	Maximum number of shares that may yet be purchased under the program authorisation
Jan-12	529,500	150.8475	4,178,800	3,821,200
Feb-12	507,000	157.7157	4,685,800	3,314,200
Mar-12	500,000	160.8828	5,185,800	2,814,200
Apr-12	540,500	149.4208	5,726,300	2,273,700
May-12	541,000	150.2483	6,267,300	1,732,700
Jun-12	584,500	139.6623	584,500	10,415,500
Jul-12	574,000	141.7508	1,158,500	9,841,500
Aug-12	547,500	149.6983	1,706,000	9,294,000
Sep-12	534,800	154.2547	2,240,800	8,759,200
Oct-12	571,350	146.4832	2,812,150	8,187,850
Nov-12	618,750	137.3701	3,430,900	7,569,100
Dec-12	625,350	137.8422	4,056,250	6,943,750
Jan-13	614,100	142.3138	4,670,350	6,329,650
Feb-13	619,000	143.2733	5,289,350	5,710,650
TOTAL	7,907,350 [2]	146.7935 [3]		

1) The authorisation to repurchase a maximum of eight million shares with a maximum overall nominal value of NOK 20 million for repurchase of shares in connection with the share savings plan was given by the annual general meeting on 19 May 2011. The authorisation was extended by the annual general meeting on 15 May 2012 to a maximum of 11 million shares with a maximum overall nominal value of 27.5 million for repurchase of shares, valid until 30 June 2013.

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 2013

07 February	Fourth quarter results and strategy update
22 March	Publication annual report 2012
02 May	First quarter 2013
14 May	Annual general meeting
15 May	Ordinary share trading ex-dividend
17 May	ADS trading ex-dividend
29 May	Ordinary share dividend payment
5 June	ADS dividend payment
25 July	Second quarter 2013
30 October	Third quarter 2013

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 (ADSs).

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 (ADRs), and each ADS represents one ordinary share. Statoil has a sponsored ADR facility with The Bank of New York Mellon (Deutsche Bank from 31 January 2013) 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				
2008	214.10	96.40	42.47	13.37
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
Quarter ended				
31 March 2011	139.00	113.70	25.78	20.16
30 June 2011	160.50	129.00	29.58	23.44
30 September 2011	139.00	113.70	25.78	20.16
31 December 2011	153.50	127.90	26.70	22.03
31 March 2012	162.40	147.10	28.92	24.88
30 June 2012	156.50	133.80	27.53	22.15
30 September 2012	154.50	140.10	26.99	23.02
31 December 2012	148.70	135.40	26.30	23.58
March up until 11 March 2013	148.00	140.80	27.00	24.70
Month of				
September 2012	154.50	147.50	26.99	25.20
October 2012	148.70	140.90	26.30	24.53
November 2012	141.20	136.00	24.71	23.58
December 2012	140.60	135.40	25.08	24.13
January 2013	148.00	141.00	26.55	25.15
February 2013	148.00	142.20	27.00	24.70
March up until 11 March 2013	142.00	140.80	24.97	24.73

6.4.2 Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.

As depositary, The Bank of New York Mellon (Deutsche Bank from 31 January 2013) 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 for making distributions to 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	· Any cash distribution to ADS registered holders
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 2012, the depositary reimbursed USD 452,999 to the company.

The table below sets forth the types of expenses that the depositary has agreed to reimburse and the amounts reimbursed during the year ended 31 December 2012:

Category of expenses	USD amount reimbursed for the year ended 31 December 2012
US investor relations expenses and other miscellaneous expenses	452,999
Total amount reimbursed	452,999 *

* Net of withholding tax paid by the Depository.

The depositary has also agreed to waive fees for standard 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 the mailing of notices and meeting material as well as the tabulation of votes in connection with the company's annual general meeting.

The table below sets forth the expenses that the depositary waived or paid directly to third parties in the year ended 31 December 2012:

Category of expenses	USD amount waived or paid for the year ended 31 December 2012
Service fees waived by the Depositary	136,884
Total amount waived or paid directly to third parties	136,884

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 28% income tax rate.

Individual shareholders resident in Norway for tax purposes are subject to the standard 28% income tax rate 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 28% income tax rate.

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 28% income tax rate.

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 1.1% of the value assessed. 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

When shares or ADSs are transferred, either through inheritance or as a gift, such transfer may give rise to inheritance tax in Norway if the deceased, at the time of death, or the donor at the time of the gift, is a resident or citizen of Norway. However, if a Norwegian citizen is 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
2008	4.9589	7.2183	5.6390	6.9989
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

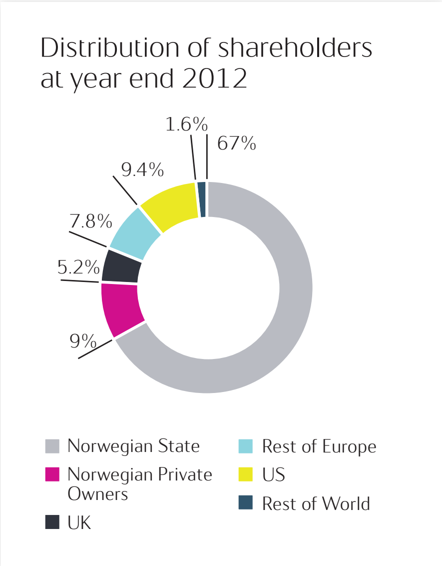
	Low	High
2012		
September	5.6728	5.8336
October	5.6236	5.7852
November	5.6565	5.7823
December	5.5383	5.6804
2013		
January	5.4871	5.6104
February	5.4438	5.7043
March (up to and including 11 March 2013)	5.6864	5.7581

On 11 March 2013, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 5.7246.

Fluctuations in the exchange rate between the Norwegian krone and the US dollar will affect the amounts in US dollars received by holders of American Depositary Shares (ADSs) on the conversion of dividends, if any, paid in Norwegian kroner on the ordinary shares, and they may affect the US dollar price of the ADSs on the New York Stock Exchange.

6.8 Major shareholders

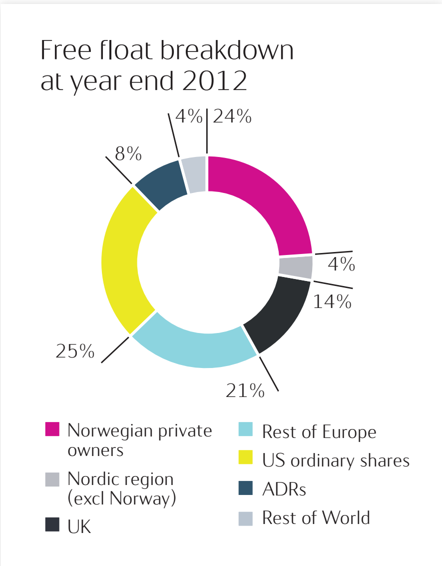
The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.



Pursuant to the exchange ratio agreed in connection with the merger with Hydro's oil and gas activities, the State's ownership interest in the merged company was 62.5%, or 1,992,959,739 shares, on 1 October 2007. In accordance with the Norwegian parliament's decision of 2001 concerning a minimum state shareholding in Statoil of two-thirds, the Government built up the State's ownership interest in Statoil by buying shares in the market during the period from June 2008 to March 2009. In March 2009, the Government announced that the State's direct ownership interest had reached 67%, and the Government's direct purchase of Statoil shares was completed.

As of 31 December 2012, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.33% indirect interest through the National Insurance Fund (Folketrygdfondet), totalling 70.33%.

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 2012.



In June 2001, in connection with the initial public offering of our ordinary shares, we established a sponsored American Depositary Receipt facility with The Bank of New York Mellon (Deutsche Bank from 31 January 2013) as depositary, pursuant to which American Depositary Receipts (ADRs) representing American Depositary Shares (ADSs) are issued. We have been informed by Deutsche Bank that in the United States, as of 11 March 2013, there were 100,197,171 ADRs outstanding (representing approximately 3% of the ordinary shares outstanding). As of 11 March 2013, there were 717 registered holders of ADRs resident in the United States. According to the Norwegian Central Securities Depository (VPS), 299,927,982 ordinary shares were held by 403 registered holders resident in the United States, representing approximately 9.5% of Statoil's ordinary shares in total. The number of beneficial holders is not known.

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 11 March 2013		Account type	Number of Shares	Ownership in %
1	The Norwegian State (Ministry of Petroleum and Energy)		2,136,393,559	67.00
2	DEUTSCHE BANK TRUST CO. AMERICAS	Nominee	101,393,776	3.18
3	Folketrygdfondet (Norwegian national insurance fund)		101,085,001	3.17
4	CLEARSTREAM BANKING	Nominee	65,696,414	2.06
5	STATE STREET BANK AND TRUST CO.	Nominee	33,090,625	1.04
6	The Bank of New York Mellon	Nominee	25,225,781	0.79
7	THE NORTHERN TRUST COMPANY SUB	Nominee	23,700,000	0.74
8	STATE STREET BANK AND TRUST CO.	Nominee	23,092,496	0.72
9	STATE STREET BANK AND TRUST CO.	Nominee	19,626,842	0.62
10	STATE STREET BANK	Nominee	17,003,579	0.53
11	JPMORGAN CHASE BANK	Nominee	13,798,966	0.43
12	SIX SIS AG	Nominee	12,423,952	0.39
13	JPMORGAN CHASE BANK S/A ESCROW ACCOUNT	Nominee	11,808,341	0.37
14	JPMORGAN CHASE BANK NORDEA TREATY ACCOUN	Nominee	10,184,313	0.32
15	EUROCLEAR BANK	Nominee	9,558,415	0.30
16	KLP AKSJE NORGE		9,037,992	0.28
17	HSBC BANK PLC	Nominee	8,902,483	0.28
18	BNYM SA/NV - BNY BRUSSELS NON-TREA	Nominee	8,597,462	0.27
19	THE NORTHERN TRUST CO.	Nominee	8,406,132	0.26
20	THE NORTHERN TRUST CO.	Nominee	7,887,087	0.25

Source: Norwegian Central Securities Depository (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 standards, 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 annual review and discussion by the board of directors.

Statoil's board of directors endorses the "Norwegian Code of Practice for Corporate Governance", last revised on 23 October 2012 (with minor corrections as of 21 December 2012). The company's compliance with and, if applicable, deviations from, the code's recommendations are commented on, and these comments are made available at Statoil.com.

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 19 May 2011.

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 9-11 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 were described in the notice of the annual general meeting 2012.

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 the 2012 annual review of the Ethics Code of Conduct, some minor changes were made, mainly in order to simplify the code, make it more reader friendly and to clarify certain requirements and responsibilities set out in the code. In addition, in 2012, the company's anti-corruption programme was reviewed in consultation with external UK and US lawyers. The review was conducted to ensure that the programme properly addresses recent legislative changes and the risks related to Statoil's activities. The Ethics Code of Conduct is available at Statoil.com, together with our anti-corruption compliance programme.

In 2012, 25,694 employees and other persons acting on Statoil's behalf completed a 90-minute e-learning course on ethics and anti-corruption. In addition to the e-learning course, Statoil runs various ethics and anti-corruption training programmes, through which 1,166 new employees attended an in-person introduction to Statoil's Ethics Code of Conduct and 634 persons attended a full-day ethics and anti-corruption workshop focusing on the requirements in our code of conduct and applicable local and international anti-corruption laws and regulations. Training in ethics and anti-corruption will continue in 2013.

Our business partners are also expected to adhere to ethical standards that are consistent with our ethical requirements.

We have a dedicated ethics helpline that can be used by employees on a 24/7 basis to express legal and ethical concerns relating to Statoil's business and activities.

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 2013 annual general meeting (AGM) is scheduled for 14 May 2013 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 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.

The members of the nomination committee are:
- Olaug Svarva (chair), managing director, Folketrygdfondet
- Live Haukvik Aker, CFO Komplett AS
- Tom Rathke, group executive vice president of insurance and asset management at DNB
- Ingrid Dramdal Rasmussen, deputy director general, tax policy department, Norwegian Ministry of Finance (former director general, department for economic and administrative affairs, Norwegian Ministry of Petroleum and Energy)

The nomination committee held 19 meetings in 2012.

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 31.12.2012	Share ownership for members as of 11.03.2013	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	Executive vice president, Orkla ASA	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	Senior Advisor, External Relations & Government Affairs, MISWACO	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	Oslo	1960	Shareholder elected	No	0	0	2007	2014
Tore Ulstein	Chairman of the Board and Deputy CEO, Ulstein Group	Ulsteinvik	1967	Shareholder elected	No	0	0	2008	2014
Live Haukvik Aker	CFO/COO, Komplett AS	Tønsberg	1963	Shareholder elected	No	0	0	2010	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 and board member, StormGeo AS	Stavanger	1970	Shareholder elected	No	0	0	2010	2014
Eldfrid Irene Hognestad	Union representative Tekna, Advisor Benchmarking	Stavanger	1966	Employee representative	No	505	658	2009	2013
Stig Lægreid	Union representative, NITO	Oslo	1963	Employee representative	No	981	1,277	2009	2013
Per Martin Labråthen	Union representative, Industri Energi. Production technician	Brevik	1961	Employee representative	No	1,150	1,333	2007	2013
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee representative	No	3,031	3,329	2006	2013
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee representative	No	450	625	2008	2013
Oddbjørn Viken	Union representative, Tekna. Production supervisor	Røyken	1961	Employee representative	No	3,142	3,477	2009	2013
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee representative, observer	No	1,701	1,890	1994	2013
Frode Solberg	Union representative, Industri Energi	Bergen	1969	Employee representative, observer	No	0	0	2009	2013
Brit Gunn Ersland	Union representative, Tekna. Specialist Reservoir Tech.	Bergen	1960	Employee representative, observer	No	1,889	2,111	2011	2013

An election of the shareholder representatives in the corporate assembly was held in May 2012. With effect from 15 May 2012, Bassim Haj was elected as a new deputy member, while Shahzad Rana left the corporate assembly as of the same date.

Pursuant to Statoil's articles of association, the corporate assembly 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.

The corporate assembly held four meetings in 2012.

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 11 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 HSE and ethics committee, and the compensation committee.

The board held eight ordinary board meetings and four extraordinary meetings in 2012. Average attendance at these board meetings was 94%.

Members of the board of directors

Svein Rennemo

Svein Rennemo
Position: Chair of the board and member of the board's compensation committee.
Born: 1947
Term of office: Chair of the board of Statoil ASA since 1 April 2008. Up for election in 2013.
Independent: Yes
Other directorships: Chair of the board of Tomra Systems ASA and Pharmaq AS.
Number of shares in Statoil ASA as of 31 December 2012: 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 2012, Svein Rennemo participated in eight ordinary board meetings, four extraordinary board meetings and seven meetings of the compensation committee. Rennemo is a Norwegian citizen and resident.

Grace Reksten Skaugen

Grace Reksten Skaugen
Position: Deputy chair of the board and chair of the board's compensation committee.
Born: 1953
Term of office: Member of the board of Statoil ASA since 2002. Up for election in 2013.
Independent: Yes
Other directorships: Chair of the board of the Norwegian Institute of Directors, and member of the board of Orkla ASA and the Swedish listed company Investor AB. Chair of the board of NAXS Nordic Access Buyout AS, a Norwegian subsidiary of the Swedish listed company Nordic Access Buyout Fund AB.
Number of shares in Statoil ASA as of 31 December 2012: 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 2012, Grace Reksten Skaugen participated in eight ordinary board meetings, four extraordinary board meetings and seven meetings of the compensation committee. Reksten Skaugen is a Norwegian citizen and resident.

Roy Franklin

Roy Franklin

Position: Member of the board, the board's audit committee and chair of the board's HSE and ethics committee.
Born: 1953
Term of office: Member of the board of Statoil ASA since 1 October 2007. Up for election in 2013.
Independent: Yes
Other directorships: Non-executive chair of the board of Keller Group plc, a London-based international engineering company. Board member of the Australian oil and gas company Santos Ltd; Boart Longyear Limited, a Salt Lake City-headquartered and Australian-listed provider of drilling services and equipment to the minerals exploration industry worldwide; and Cuadrilla Resources Holdings Limited, a privately held UK company focusing on unconventional energy sources.
Number of shares in Statoil ASA as of 31 December 2012: None
Loans from Statoil: None
Experience: Franklin has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Bachelor of science in geology from the University of Southampton, UK.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2012, Roy Franklin participated in seven ordinary board meetings, four extraordinary board meetings, four meetings of the audit committee and five meetings of the board's HSE and ethics committee. Franklin is a UK citizen and resident. In 2004, he was awarded an OBE for his work for the British oil and gas industry.

Bjørn Tore Godal

Bjørn Tore Godal

Position: Member of the board, the board's compensation committee and the board's HSE and ethics committee.
Born: 1945
Term of office: Member of the board of Statoil ASA from 1 September 2010. Up for election in 2013.
Independent: Yes
Other directorships: Chairman of the Council of the Norwegian Defence University College (NDUC).
Number of shares in Statoil ASA as of 31 December 2012: None
Loans from Statoil ASA: None
Experience: Godal was a member of the Norwegian parliament for 15 years during the period 1986-2001. At various times, he served as minister for trade and shipping, minister for 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 2012, Bjørn Tore Godal participated in eight ordinary board meetings, two extraordinary board meetings, seven meetings of the board's compensation committee and five meetings of the board's HSE and ethics committee. Godal is a Norwegian citizen and resident.

Lady Barbara Judge

Lady Barbara Judge

Position: Member of the board and the board's audit committee.
Born: 1946
Term of office: Member of the board of Statoil ASA since 1 September 2010. Up for election in 2013.
Independent: Yes
Other directorships: Board member and chair of the UK Pension Protection Fund, board member of NV Bekaert SA and Magna International Inc and chair of the Energy Institute of University College London.
Number of shares in Statoil ASA as of 31 December 2012: 5,291
Loans from Statoil ASA: None
Experience: Judge has served for 10 years as a commercial lawyer focusing on securities and corporate finance. In 1980, she became the youngest person ever appointed by the president of the United States to the position of commissioner, US Securities and Exchange Commission. Between 1984 and 1994, she held a number of senior executive positions in the finance industry. Since 1994, she has developed a broad portfolio of public and private non-executive and advisory roles focusing on energy and regulatory frameworks. Among other things, she served as executive chair of the UK Atomic Energy Authority from 2004 to 2010, has been deputy chair of the Financial Reporting Council, the UK regulatory authority for accounting and corporate governance, and a board member of the energy group of the UK Department of Trade and Industry. From 2000 to 2005, Judge was a founder and executive chair of Private Equity Investor PLC in London.
Education: Lady Barbara Judge is a JD with honours from New York University Law School and has a bachelor of arts degree in history from the University of Pennsylvania.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2012, Lady Barbara Judge participated in seven ordinary board meetings, three extraordinary board meetings and six meetings of the audit committee. Lady Judge holds American and British citizenships, lives in London and has been awarded an OBE.


Jakob Stausholm

Jakob Stausholm
Position: Member of the board and chair of the board's audit committee.
Born: 1968
Term of office: Member of the board of Statoil ASA since July 2009. Up for election in 2013.
Independent: Yes
Other directorships: No
Number of shares in Statoil ASA as of 31 December 2012: 16,600
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: Master of science 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 2012, Jakob Stausholm participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the board's audit committee. Stausholm is a Danish citizen and lives in Denmark.


Maria Johanna Oudeman

Maria Johanna Oudeman
Position: Member of the board and member of the board's audit committee.
Born: 1958
Term of office: Member of the Board of Statoil ASA from 15 September 2012.
Other board positions: Oudeman is a member of the boards of Nederlandske Spoorwegen, ABN Amro Group and Het Concertgebouw and Rijksmuseum in Amsterdam, the Netherlands.
Number of shares in Statoil ASA as of 31 December 2012: None
Loans in Statoil: None
Experience: Oudeman is 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 a major producer of specialty chemicals, with operations in more than 80 countries. 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 Gröningen in the Netherlands and an MBA in business administration from the University of Rochester, New York, USA and Erasmus University, Rotterdam, the Netherlands.
Other matters: In 2012, Marjan Oudeman participated in one ordinary board meeting and one meeting of the board's audit committee. Oudeman is a Dutch citizen and lives in the Netherlands.


Børge Brende

Børge Brende
Position: Member of the board and member of the board's HSE & ethics committee.
Born: 1965
Term of office: Member of the board of Statoil ASA from 15 September 2012.
Other board positions: Chairman of the board of Mesta and vice-chairman of China Council, an advisory body for the Chinese government on environmental issues
Number of shares in Statoil ASA as of 31 December 2012: None
Loans in Statoil: None
Experience: Brende's extensive political and international experience includes serving as Norwegian minister of the environment (2001-2004) and Norwegian minister of trade and industry (2004-2005). He was a member of the Norwegian parliament from 1997-2009. Brende has also been secretary general of the Norwegian Red Cross and head of the UN Commission on Sustainable Development. He has been the managing director of the World Economic Forum since 2011.
Education: Bachelor of arts from the Norwegian University of Science and Technology (NTNU), Trondheim 1997.
Other matters: In 2012, Børge Brende participated in two ordinary board meetings and two extraordinary board meetings. Børge Brende is a Norwegian citizen and lives in Norway and Geneva, Switzerland.

Lill-Heidi Bakkerud

Lill-Heidi Bakkerud
Position: Employee-elected member of the board and member of the board's HSE and ethics committee.
Born: 1963.
Term of office: Member of the board of Statoil ASA from 1998 to 2002, and again since 2004. Up for election in 2013.
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 2012: 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 2012, Lill-Heidi Bakkerud participated in eight ordinary board meetings, four extraordinary board meetings and four meetings of the board's HSE and ethics committee. Bakkerud is a Norwegian citizen and resident.

Morten Svaan

Morten Svaan
Position: Employee-elected member of the board and member of the board's audit committee.
Born: 1956
Term of office: Member of the board of Statoil ASA since 2004. Up for election in 2013.
Independent: No
Other directorships: None
Number of shares in Statoil ASA as of 31 December 2012: 2,835
Loans from Statoil: None
Experience: Svaan has worked for Statoil since 1985. He now works on health, safety and the environment (HSE) for the Technology, Projects and Drilling business area, largely focusing on security and emergency response. Svaan was chief employee representative for the Statoil branch of the NIF/Tekna trade union from 2000 until 2004.
Education: He has a doctorate in chemistry from the Norwegian University of Science and Technology and a degree in business economics 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 2012, Morten Svaan participated in eight ordinary board meetings, four extraordinary board meetings and six meetings of the board's audit committee. Svaan is a Norwegian citizen and resident.

Einar Arne Iversen

Einar Arne Iversen
Position: Employee-elected member of the board.
Born: 1962
Term of office: Member of the corporate assembly of Statoil ASA from 2000 to 2009. Member of the board of Statoil ASA since June 2009. Up for election in 2013.
Independent: No
Other directorships: None
Number of shares in Statoil ASA as of 31 December 2012: 3,952
Loans from Statoil: None
Experience: Iversen joined Statoil in 1986, worked on technical training in Bergen and was training manager at Tjeldbergodden. He has held the offices of deputy head/head of the NITO trade union since 1998.
Education: He qualified as an engineer at the NKI Technical College in 1982.
Family relations: No family relations to other members of the board, members of the corporate executive committee or the corporate assembly.
Other matters: In 2012, Einar Arne Iversen participated in eight ordinary board meetings and four extraordinary board meetings. Iversen is a Norwegian citizen and resident.

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 representatives on the board of directors may nominate one audit committee member.

At year-end 2012, the audit committee members were Jakob Stausholm (chair), Barbara Judge, Roy Franklin, Maria Johanna Oudeman and Morten Svaan (employee representative).

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 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, refer to the Norwegian Auditors Act chapter 4, and, in particular, whether other services 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 elected 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. KPMG was elected as new auditor for Statoil ASA at the annual general meeting in 2012.

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 connection, 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 2012. There was 92% 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 is 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 committee

The compensation 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 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 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 2012, 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 seven meetings in 2012 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 HSE and ethics committee

The HSE and ethics committee is a sub-committee of the board of directors that assists the board in matters relating to health, safety and the environment (HSE), ethics and corporate social responsibility (CSR).

Statoil's board of directors has established a sub-committee dedicated to the areas of HSE, ethics and CSR. The HSE and ethics committee (the committee) is chaired by Roy Franklin, and the other members are Bjørn Tore Godal, Børge Brende and Lill-Heidi Bakkerud.

In its business activities, Statoil is committed to complying with applicable laws and regulations and to acting in an ethical, sustainable, 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 HSE, ethics and CSR policies, systems and principles.

Establishing and maintaining a committee dedicated to HSE, ethics and CSR is intended to ensure that the board of directors has an even stronger focus on and greater 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 HSE, ethics and CSR.

The committee held five meetings in 2012, and attendance was 83%.

For a more detailed description of the objective, duties and composition of the committee, please see the instructions for the HSE and ethics committee available at Statoil.com/hseethicscommittee.

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, an HSE and ethics committee and a compensation committee. They are responsible for preparing certain matters for the board of directors. The audit committee and the compensation 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's board of directors does not have a nominating/corporate governance board sub-committee. 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.

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. Although the issuance of shares and authority to buy back company shares must be approved by Statoil's annual general meeting of shareholders under Norwegian company law, 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

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 2012: 51,079
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.

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 2012: 16,128
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.


Tove Stuhr Sjøblom. Chief staff officer (CSO)

Tove Stuhr Sjøblom
Born: 1966
Position: Executive vice president, chief staff officer (CSO) in Statoil ASA from 1 January 2011-31 December 2012 *
External offices: None.
Number of shares in Statoil as of 31 December 2012: 7,917
Loans from Statoil: None
Experience: Has held several managerial positions in Statoil since 2007, including the position of senior vice president for exploration in Exploration & Production Norway. With Norsk Hydro ASA from 1991-2007, where she held various managerial positions including in exploration, asset management and project management. She was in Canada from 2000-2003 (seconded to Petro-Canada from 2000-2002).
Education: Master of science from the Norwegian University of Science and Technology (NTNU).
Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.
Other matters: Tove Stuhr Sjøblom holds both Norwegian and Canadian citizenships and lives in Norway.


Eldar Sætre. Executive vice president Marketing, Processing and Renewable energy

Eldar Sætre
Born: 1956
Position: Executive vice president in Statoil ASA since October 2003.
External offices: Member of the board of Strømberg Gruppen AS and Trucknor AS.
Number of shares in Statoil ASA as of 31 December 2012: 21,405
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.


Øystein Michelsen. Executive vice president Development and Production Norway

Øystein Michelsen
Born: 1956
Position: Executive vice president in Statoil ASA since 10 November 2008.
External offices: Member of the board of the Norwegian Oil and Gas Association
Number of shares in Statoil ASA as of 31 December 2012: 19,019
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.


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 2012: 13,715
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.


William Maloney. Executive vice president Development and Production North America.

William Maloney
Born: 1955
Position: Executive vice president 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 2012: 18,132
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.


John Knight. Executive vice president Global Strategy and Business Development

John Knight
Born: 1958
Position: Executive vice president in Statoil ASA from 1 January 2011.
External offices: None
Numbers of shares in Statoil ASA as of 31 December 2012: 40,264
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 he lives in England.

Tim Dodson. Executive vice president, Exploration

Tim Dodson
Born: 1959
Position: Executive vice president in Statoil ASA since 1 January 2011.
External offices: None
Number of shares in Statoil ASA as of 31 December 2012: 15,553
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 lives in Norway.

Margareth Øvrum. Executive Vice President Technology, Projects and Drilling

Margareth Øvrum
Born: 1958
Position: Executive vice president in Statoil ASA since September 2004.
External offices: Member of the board of Atlas Copco AB and Ratos AB.
Number of shares in Statoil ASA as of 31 December 2012: 26,576
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.

*) Following the new corporate staff structure, effective from 1 January 2013, there is no CSO role in the corporate executive committee.

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 2012, aggregate compensation totalling NOK 989,000 was paid to the members of the corporate assembly, NOK 4,853,000 to the members of the board of directors and NOK 73,593,000 to the members of the corporate executive committee (all in round figures).

Detailed information about the individual compensation paid to the members of the board of directors and members of the corporate executive committee in 2012 is provided in the tables below.

Members of the board (In NOK thousand)	Board remuneration	Audit committee	Compensation committee	HSEE committee	Total remuneration
Svein Rennemo	655		48		703
Marit Arnstad*	203			8	211
Grace Reksten Skaugen	359		78		437
Roy Franklin	432	120		95	647
Jakob Stausholm	334	185			519
Bjørn Tore Godal	334		56	40	430
Lady Barbara Singer Judge	432	120			552
Lill-Heidi Bakkerud	334			32	366
Morten Svaan	334	120			454
Einar Arne Iversen	334				334
Børge Brende**	100				100
Maria Johanna Oudeman**	100				100
Total	3,951	545	182	175	4,853

* Member until and including 19 June 2012
** Member from 15 September 2012

Management remuneration in 2012 (in NOK thousands)

	Fixed remuneration											
Members of corporate executive committee	Base pay 1)	LTI 2)	Annual variable pay	Taxable benefits in kind	Taxable reimburse-ments	Taxable salary	Non-taxable benefits in kind	Non-taxable reimburse-ments	Non-taxable salary	Total remune-ration	Estimated pension cost 3)	Estimated present value of pension obligation
Lund Helge (CEO)	7,224	2,050	3,307	681	16	13,278	537	26	563	13,841	4,950	37,515
Reitan Torgrim (CFO)	2,721	640	1,102	113	13	4,589	0	31	31	4,620	666	10,965
Sjøblom Tove Stuhr (Executive vice president Corporate staffs and services)	2,472	582	723	317	6	4,100	269	54	323	4,423	646	14,020
Mellbye Peter (Executive vice president Development & Production International, until 1 September 2012) 4)	2,575	583	958	243	7	4,366	0	15	15	4,381	1,057	41,485
Bacher Lars Christian (Executive vice president Development & Production International, from 1 September 2012) 4)	935	65	0	81	3	1,084	203	15	218	1,302	552	10,424
Dodson Timothy (Executive vice president Exploration)	3,151	706	1,215	135	22	5,229	382	85	467	5,696	1,081	16,982
Øvrum Margareth (Executive vice president, Technology, Projects & Drilling)	3,570	810	1,205	199	12	5,796	195	39	234	6,030	1,127	34,192
Michelsen Øystein (Executive vice president Development & Production Norway)	3,372	812	1,009	379	7	5,579	277	58	335	5,914	875	26,309
Sætre Eldar (Executive vice president Marketing, Processing and Renewable Energy)	3,417	810	1,005	395	23	5,650	0	46	46	5,696	1,046	32,532
Maloney William (Executive vice president Development & Production North America) 5)	3,851	2,353	2,353	710	9	9,276	139	0	139	9,415	602	0
Knight John (Executive vice president Global Strategy & Business Development) 5)	4,983	3,269	3,269	754	0	12,275	0	0	0	12,275	997	0
Total	38,271	12,680	16,146	4,007	118	71,222	2,002	369	2,371	73,593	13,599	224,424

1a) The CEO's base salary increase as of 1 January 2012 was 3.25%.

1b) Base pay consists of base salary, holiday allowance and any other administrative benefits.

2) The fixed long-term incentive (LTI) element entails an obligation to invest the net amount in Statoil shares. A lock-in period of three years applies for the investment. 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 that deviates 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 at 31 December 2012 and is recognised as pension cost in the statement of income for 2012. Payroll tax is not included.
Members of the corporate executive committee employed by non-Norwegian subsidiaries have a defined contribution scheme.
4) Remuneration for Mellbye and Bacher apply to their respective period of service on the corporate executive committee.
5) Members of the corporate executive committee employed by non-Norwegian subsidiaries and not resident in Norway.

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 2013 annual general meeting:

1. Remuneration policy and concept for the accounting year 2012

1.1 Policy and principles
In general, the company's established remuneration principles and general concepts will be continued in the accounting year 2013. Statoil's remuneration policy is closely linked to the company's core values and people policy. Certain key principles have been adopted for the design of our remuneration concept.

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 people 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.

Our rewards and recognition are designed to attract and retain the right people - people who perform, change and learn. The overall remuneration level and the balance between the individual components reflect the national and international framework and business environment in which we operate.

1.2 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 the 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 as amended on 5 September 2012, with effect from 1 December 2012. The Board's Rules of Procedures are available on Statoil.com.

The board of directors has appointed a separate compensation committee. The compensation 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 of 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. For further details about the roles and responsibilities of the compensation committee, please refer to the committee's instructions, which are available on Statoil.com.

1.3 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
- Variable pay
- Pensions and insurance schemes
- Severance schemes
- Other benefits

The evaluation of changes to the company's general pension system initiated in 2012 will continue in 2013. This also includes pension accruals for pensionable salary above 12 times the national insurance basic amount (G).

Deviations from the general principles outlined below relating to two members of the corporate executive committee, implemented with effect from 1 January 2011, are described in section 2.1 below. These deviations have also been described in previous statements on remuneration and other terms of employment for Statoil's corporate executive committee.

Fixed remuneration
Fixed remuneration consists of base salary and a long-term incentive system.

Base salary
We offer base salary levels which are aligned with the individual's responsibility and performance at a level that is competitive in the markets in which we operate. The evaluation of performance is based on the fulfilment of pre-defined goals, see "Variable pay" below. The base salary is normally subject to annual review.

Long-term incentive (LTI)
Statoil will continue the established long-term incentive system for a limited number of senior executives and key professional positions. Members of the corporate executive committee are included in the scheme.

The long-term incentive system is a fixed, monetary compensation calculated as a proportion 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.

The long-term incentive and the annual variable pay schemes constitute a remuneration concept focusing both on short- and long-term goals and results. By ensuring that our top executives are holders of company shares, the long-term incentive contributes to strengthening the common interests between the top management and our shareholders.

Variable pay
The maximum potential for variable pay in the parent company is 50% of the fixed remuneration. The company's performance-based variable pay concept will be continued in 2013.

The chief executive officer is entitled to annual variable pay amounting to 25% of his fixed remuneration conditional on accomplishing agreed targets. If agreed targets are exceeded, the reward will be in the range from 25-50 % of his fixed remuneration. Correspondingly, the executive vice presidents have an annual variable pay scheme comprising a target of 20% conditional on accomplishing agreed goals. The maximum variable pay potential for this group is 40% of the fixed remuneration.

Remuneration policies' effect on risk
The remuneration concept is an integrated part of our performance management system. It is an overarching principle that there should be a close link between performance and remuneration.

Individual salary and annual variable pay reviews are based on the performance evaluation in our performance management system. Participation in the long-term incentive (LTI) scheme and the size of the annual LTI element reflect the level and impact of the position and are not directly linked to the incumbent's performance.

The goals forming the basis for the performance assessment are established between the manager and the employee as part of our performance management process. The performance goals are set in two dimensions -delivery and behaviour - which are weighted equally. Delivery goals are established for each of the five perspectives: people and organisation, HSE, operations, market, and finance. In each perspective, both long-term strategic objectives and short-term targets and key performance indicators (KPI) are defined together with relevant actions. Behaviour goals are based on our core values and leadership principles. They address the behaviour required and expected in order to achieve our delivery goals.

The performance evaluation is a holistic evaluation combining measurement and assessment of performance against both delivery and behaviour goals. The KPIs are used as *indicators* only. Hence, sound judgement and hindsight are applied before final conclusions are drawn. Measured KPI results are reviewed in relation to their strategic contribution, sustainability and significant changes in assumptions.

This balanced scorecard approach, which involves a broad set of goals defined in relation to both the delivery and behaviour dimensions and an overall performance evaluation is perceived as significantly reducing the likelihood that remuneration policies will stimulate excessive risk-taking or have other material adverse effects.

In the performance contracts of the chief executive officer and chief financial officer, one of several targets is related to the company's relative total shareholder return (TSR). The amount of the annual variable pay is decided based on an overall assessment of the performance in relation to various targets, including but not limited to the company's relative TSR.

Pension and insurance schemes
Statoil ASA's current general pension plan is a defined benefit arrangement 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. The general retirement age is 67 for employees onshore and 65 for offshore employees.

The pension schemes for members of the corporate executive committee including the chief executive officer are 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% 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 under a previous standard arrangement implemented in October 2006. Subject to specific terms, those executives are entitled to a pension amounting to 66% 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 confer a right to 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 of Statoil's executive vice presidents have an individually agreed retirement age of 65 and an early-retirement pension level of 66% of pensionable salary.

The individual pension terms for executive vice presidents outlined above are the result of commitments under previously established agreements.

The company's standard pension arrangements for executive vice presidents that deviate from Statoil ASA's general pension plan have been discontinued and will not apply to new appointees to the corporate executive committee.

The most recently appointed executive vice president's pension terms entail a continuation of his previous pension arrangements, which are in alignment with the current general pension terms of the company. Pension accruals for pensionable salary above 12 times the National Insurance basic amount (G) are accounted for in the profit and loss account and 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 in Statoil.

The executive vice presidents employed outside the parent company have defined contribution schemes (16% and 20% contributions respectively) in accordance with the framework established in their local employment companies. The pension contribution is paid into a separate legal entity.

The process of evaluating changes to the general pension scheme in the parent company will be continued in 2013. This evaluation includes assessing the question of replacing the current defined benefit scheme with a defined contribution plan and the prevailing pension scheme for salaries exceeding 12 times the National Insurance basic amount (G). This project is planned to conclude after the Banking Law Commission's recommendations are passed by the parliament.

A revised pension scheme for new members of the corporate executive committee will be designed and implemented when the changes to the overall pension system have been determined.

Severance schemes

Under the terms of his contract of 7 March 2004, the chief executive officer is entitled to a 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 expiry of the period of notice of six 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-month period of notice, when the resignation is at the company's request. 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 trigger any severance pay.

Other benefits

Statoil has a share savings plan that is 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 5% 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 a company car and electronic communication.

2. Execution of the remuneration policy and principles in 2012

2.1 Deviations from the statement on executive remuneration 2012

Two members of the executive committee have variable pay schemes that deviate from the description 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 in the respective locations.

2.2 Development in actual remuneration

During the last five-year period, the framework for the annual base salary review has been lower for the corporate executive committee than for employees encompassed by collective bargaining agreements in the company. In this period, the merit increase for executive vice presidents employed in the parent company has been determined within an annual average framework of 3.2%. During the same period the CEO's average annual base salary increase has been 2.35% while his average annual variable pay was 27.5% of his fixed remuneration. The annual variable pay for 2012 (37.5% of his fixed remuneration) was higher than the average for the period, reflecting the company's strong performance. The average annual variable pay for the CEO reflects the fact that the maximum pay potential for 2008 and 2009 was reduced by 50% as a consequence of the financial crisis.

2.3 Changes in the corporate executive committee in 2012

Executive vice president Development and Production International, Peter Mellbye, retired from his position on 31 August 2012 on terms and conditions in accordance with his pension agreement of 15 November 1994. Mellbye was succeeded by executive vice president Lars Christian Bacher.

A change in the corporate organisational structure was decided in 2012, leading to the discontinuation of the position of executive vice president and chief of staff, effective from 1 January 2013.

3. Concluding remarks

Statoil's remuneration policy and solutions are aligned with the company's overall values, people policy and performance-oriented framework. In closing, the remuneration systems and practices are transparent and deviations are explained in accordance with prevailing guidelines and good corporate governance.

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 2012	As of 11 March 2013
Members of the corporate executive committee		
Helge Lund	51,079	53,459
Torgrim Reitan	16,128	16,835
Margareth Øvrum	26,576	27,826
Eldar Sætre	21,405	22,318
Øystein Michelsen	19,019	20,159
Lars Christian Bacher	13,715	14,763
Tim Dodson	15,553	16,286
William Maloney	18,132	18,447
John Knight	40,264	40,264
Tove Stuhr Sjøblom*	7,917	
Members of the board of directors		
Svein Rennemo	10,000	10,000
Grace Reksten Skaugen	400	400
Bjørn Tore Godal	0	0
Lady Barbara Judge	5,291	5,291
Jakob Stausholm	16,600	16,600
Roy Franklin	0	0
Maria Johanna Oudeman	0	0
Børge Brende	0	0
Lill-Heidi Bakkerud	330	330
Morten Svaan	2,835	3,160
Einar Arne Iversen	3,952	4,207

* Tove Stuhr Sjøblom was member of the corporate executive committee until 31 December 2012.

Individually, each member of the corporate assembly owned less than 1% of the outstanding Statoil shares as of 31 December 2012 and as of 11 March 2013. In aggregate, members of the corporate assembly owned a total of 12,849 shares as of 31 December 2012 and a total of 14,700 shares as of 11 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 stipulate 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 2012
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.

On 15 May 2012, the general meeting of shareholders appointed KPMG AS as Statoil's auditor, thereby replacing Ernst & Young AS as of that date. The following table sets out the aggregate fees related to professional services rendered by Statoil's principal accountant KPMG, for the fiscal year 2012, and Ernst & Young for the fiscal year 2010, 2011 and until 15 May 2012.

Auditor's remuneration (in NOK million, excluding VAT)	For the year ended 31 December 2012	 2011	 2010
Audit fees KPMG (principal accountant 2012, as from 15 May 2012)	22	0	0
Audit fees Ernst & Young (principal accountant 2011 and 2010)	22	63	65
Audit-related fees (KPMG for 2012, Ernst & Young for 2011 and 2010)	9	7	14
Tax fees (KPMG for 2012, Ernst & Young for 2011 and 2010)	2	0	0
All other fees (KPMG for 2012, Ernst & Young for 2011 and 2010)	2	3	0
Total	57	73	79

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 2012, 2011 and 2010 amounted to NOK 7 million, NOK 9 million and NOK 9 million, respectively.

Item 16 F: Change in registrant's certifying accountant

The annual general meeting of shareholders held 15 May 2012 elected KPMG as the independent auditor commencing with accounting year 2012 based upon the recommendation of the audit committee. As a result, Ernst & Young AS ("Ernst & Young") was dismissed as of 15 May 2012. Statoil had performed a comprehensive review and evaluation of relevant candidates as part of work to periodically assess the independent auditor consistent with corporate governance standards. Ernst & Young had been Statoil's auditor for more than 20 years.

Ernst & Young's reports on the Consolidated financial statements for the years ended 31 December 2011 and 2010 did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty, audit scope or accounting principles. In connection with the audits of our financial statements for each of the years ended 31 December 2011 and 2010, and through the period ended 15 May 2012, there were no disagreements with Ernst & Young on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure during the two years ended 31 December 2011, that if not resolved to the satisfaction of Ernst & Young, would have caused it to make reference to the subject matter of the disagreements in connection with its report.

In connection with the audits of our consolidated financial statements for the two years ended 31 December 2011 and 2010, and through the period ended 15 May 2012, none of the reportable events described in paragraphs (A) through (D) of Item 16F(a)(1)(v) of Form 20-F occurred.

Statoil engaged KPMG as our new independent registered public accounting firm as of 15 May 2012. In connection with the audits of the financial statements for each of the two years ended 31 December 2011 and 2010, and through the period ended 15 May 2012, neither Statoil nor anyone on its behalf has consulted with KPMG on the application of accounting principles to a specified transaction, either completed or proposed; or the type of audit opinion that might be rendered on Statoil's consolidated financial statements or any matter that was the subject of a disagreement, as that term is defined in Item 16F(a)(1)(iv) of Form 20-F and the related instructions to Item 16F of Form 20-F, or a reportable event, as that term is defined in Item 16F(a)(1)(v).

Statoil has provided Ernst & Young with a copy of these disclosures prior to the filing hereof and has requested that Ernst & Young furnish to the company a letter addressed to the Securities and Exchange Commission stating whether Ernst & Young agrees with the statements made by Statoil in this item. Ernst & Young has furnished such letter, which letter is filed as Exhibit 15(a)(v) hereto as required by Item 16F(a)(3) of Form 20-F.

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 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 2012 was effective.

Statoil's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets, provide reasonable assurance that transactions are recorded in the manner necessary to permit the preparation of financial statements in accordance with IFRS, and that receipts and expenditures are only carried out in accordance with the authorisation of the management and directors of Statoil; and provide reasonable assurance regarding the prevention or timely detection of any unauthorised acquisition, use or disposition of Statoil's assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Moreover, projections of any evaluation of the effectiveness of internal control to future periods are subject to a risk that controls may become inadequate because of changes in conditions and that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of internal control over financial reporting as of 31 December 2012 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

(in NOK billion)	Note	For the year ended 31 December 2012	2011	2010
Revenues		705.7	645.6	527.0
Net income from associated companies		1.7	1.3	1.1
Other income	5	16.0	23.3	1.8
Total revenues and other income	4	723.4	670.2	529.9
Purchases [net of inventory variation]		(363.1)	(319.6)	(257.4)
Operating expenses		(64.0)	(60.4)	(57.6)
Selling, general and administrative expenses		(11.1)	(13.2)	(11.1)
Depreciation, amortisation and net impairment losses	12, 13	(60.5)	(51.4)	(50.7)
Exploration expenses	13	(18.1)	(13.8)	(15.8)
Net operating income	4	206.6	211.8	137.3
Net financial items	9	0.1	2.0	(0.5)
Income before tax		206.7	213.8	136.8
Income tax	10	(137.2)	(135.4)	(99.2)
Net income		69.5	78.4	37.6
Attributable to equity holders of the company		68.9	78.8	38.1
Attributable to non-controlling interests		0.6	(0.4)	(0.5)
Basic earnings per share (in NOK)	11	21.66	24.76	11.97
Diluted earnings per share (in NOK)	11	21.60	24.70	11.94

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK billion)	Note	For the year ended 31 December 2012	2011	2010
Net income		69.5	78.4	37.6
Actuarial gains (losses) on defined benefit pension plans	21	5.5	(7.4)	0.0
Income tax effect on income and expense recognised in OCI		(1.5)	2.0	0.0
Items that will not be reclassifed to statement of income		4.0	(5.4)	0.0
Foreign currency translation differences		(11.9)	6.1	2.0
Change in fair value of available for sale financial assets	14	0.0	(0.2)	0.2
Items that may be subsequently reclassified to statement of income		(11.9)	5.9	2.2
Other comprehensive income		(7.9)	0.5	2.2
Total comprehensive income		61.6	78.9	39.8
Attributable to equity holders of the company		61.0	79.3	40.3
Attributable to non-controlling interests		0.6	(0.4)	(0.5)

CONSOLIDATED BALANCE SHEET

(in NOK billion)	Note	2012	At 31 December 2011 (restated)	2010 (restated)
ASSETS				
Property, plant and equipment	12	439.1	407.6	351.6
Intangible assets	13	87.6	92.7	43.2
Investments in associated companies		8.3	9.2	9.0
Deferred tax assets	10	3.9	5.7	1.9
Pension assets	21	9.4	3.9	5.3
Derivative financial instruments	28	33.2	32.7	20.6
Financial investments	14	15.0	15.4	15.3
Prepayments and financial receivables	14	4.9	3.3	3.9
Total non-current assets		601.4	570.5	450.8
Inventories	15	25.3	27.8	23.6
Trade and other receivables	16	74.0	103.8	75.9
Derivative financial instruments	28	3.6	6.0	6.1
Financial investments	17	14.9	5.2	8.2
Cash and cash equivalents	18	65.2	55.3	33.8
Total current assets		183.0	198.1	147.6
Assets classified as held for sale	5	0.0	0.0	44.9
Total assets		784.4	768.6	643.3
EQUITY AND LIABILITIES				
Shareholders' equity		319.2	278.9	219.5
Non-controlling interests		0.7	6.3	6.9
Total equity	19	319.9	285.2	226.4
Bonds, bank loans and finance lease liabilities	20	101.0	111.6	99.8
Deferred tax liabilities	10	81.2	82.5	78.1
Pension liabilities	21	20.6	27.0	22.1
Provisions	22	95.5	87.3	68.0
Derivative financial instruments	28	2.7	3.9	3.4
Total non-current liabilities		301.0	312.3	271.4
Trade and other payables	23	81.8	94.0	73.7
Current tax payable	10	62.2	54.3	46.7
Bonds, bank loans, commercial papers and collateral liabilities	24	18.4	19.8	11.7
Derivative financial instruments	28	1.1	3.0	4.2
Total current liabilities		163.5	171.1	136.3
Liabilities directly associated with the assets classified as held for sale	5	0.0	0.0	9.2
Total liabilities		464.5	483.4	416.9
Total equity and liabilities		784.4	768.6	643.3

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	Statoil shareholders' equity	Non-controlling interests	Total equity
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
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
At 31 December 2009	8.0	40.8	145.9	0.0	3.6	198.3	1.8	200.1
Net income for the period			38.1			38.1	(0.5)	37.6
Other comprehensive income			0.0	0.2	2.0	2.2		2.2
Dividends paid			(19.1)			(19.1)		(19.1)
Other equity transactions		0.0	0.0			0.0	5.6	5.6
At 31 December 2010	8.0	40.8	164.9	0.2	5.6	219.5	6.9	226.4

Refer to note 19 *Shareholders' equity*.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	Note	For the year ended 31 December 2012	2011 (restated)	2010 (restated)
Income before tax		206.7	213.8	136.8
Adjustments for:				
Depreciation, amortisation and net impairment losses	12,13	60.5	51.4	50.7
Exploration expenditures written off		3.1	1.5	2.9
(Gains) losses on foreign currency transactions and balances		3.3	4.2	1.6
(Gains) losses on sales of assets and other items	5	(21.7)	(27.7)	(1.2)
(Increase) decrease in inventories		0.8	(4.1)	(3.4)
(Increase) decrease in trade and other receivables		10.8	(14.4)	(16.7)
Increase (decrease) in trade and other payables		(7.0)	20.4	9.5
(Increase) decrease in net derivative financial instruments	28	(1.1)	(12.8)	(0.6)
Taxes paid		(119.9)	(112.6)	(92.3)
(Increase) decrease in non-current items related to operating activities		(7.5)	(0.7)	(2.1)
Cash flows provided by operating activities		128.0	119.0	85.2
Additions through business combinations	5	0.0	(25.7)	0.0
Additions to property, plant and equipment		(96.0)	(85.1)	(68.4)
Exploration expenditures capitalised and additions to other intangibles		(16.4)	(7.2)	(15.0)
(Increase) decrease in financial investments		(12.1)	3.8	(2.8)
(Increase) decrease in non-current loans granted and other non-current items		(1.9)	(0.5)	0.9
Proceeds from sales of assets and businesses	5	29.8	29.8	1.9
Prepayment received related to the held for sale transactions		0.0	0.0	4.1
Cash flows used in investing activities		(96.6)	(84.9)	(79.3)
New non-current loans and issuance of bonds		13.1	10.1	15.6
Repayment of non-current bonds, bank loans and finance lease liabilities		(12.2)	(7.4)	(3.3)
Dividend paid	19	(20.7)	(19.9)	(19.1)
Net current loans and other		1.6	4.5	6.0
Cash flows provided by (used in) financing activities		(18.2)	(12.7)	(0.8)
Net increase (decrease) in cash and cash equivalents		13.2	21.4	5.1
Effect of exchange rate changes on cash and cash equivalents		(1.9)	(0.2)	0.3
Cash and cash equivalents at the beginning of the period (net of overdraft)	18	53.6	32.4	27.0
Cash and cash equivalents at the end of the period (net of overdraft)	18	64.9	53.6	32.4
Interest paid		3.6	3.9	2.6
Interest received		2.6	2.7	2.1

Proceeds from sales of assets and businesses for the year ended 31 December 2012 include NOK 13.9 billion from the sale of a 24.1% ownership interest in the Gassled joint venture in 2011.

Cash and cash equivalents include a net bank overdraft of NOK 0.3 billion at 31 December 2012, NOK 1.7 billion at 31 December 2011 and NOK 1.4 billion at 31 December 2010.

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 2012 were authorised for issue in accordance with a resolution of the board of directors on 11 March 2013.

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.

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 standards, standard amendments and interpretations applicable to Statoil have been issued but were not yet effective and will be adopted by Statoil on 1 January 2013. Except where otherwise stated, standards and amendments require retrospective implementation, but have been assessed to be immaterial in regard to their impact on Statoil's accounts for previous reporting periods.

- IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements* and IFRS 12 *Disclosure of Interests in Other Entities*, issued in May 2011 and with transition guidance amendments issued in June 2012, and the amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*, issued in May 2011, will be implemented by Statoil simultaneously in the financial statements. 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. IFRS 10 introduces a new control model that applies to all entities and requires judgement to determine whether an entity is controlled and should be consolidated when there is less than a majority of voting rights, or whether there is a loss of control. The standard will not lead to significant changes in entities deemed to be controlled by Statoil. IFRS 11 introduces a substance over form approach that requires judgement in evaluating joint control and requires the unanimous consent of all the parties, or of a group of parties that collectively control an arrangement, for it to be defined as jointly controlled and for IFRS 11 to apply. The standard provides that a company will account for joint operations, where the company has rights to the assets and the liabilities of the joint operation, similar to the proportionate consolidation method. Joint ventures, where the company has rights to the net assets, will be accounted for using the equity method. Statoil has not identified significant entities or activities within the scope of IFRS 11 that will be accounted for differently under the new standard. Those of Statoil's exploration and production licence activities that are within the scope of the standard will be accounted for in a manner similar to proportionate consolidation. The adoption on 1 January 2013 of IFRS 10, IFRS 11 and IFRS 12 and their respective amendments, as well as of the amendments to IAS 28, will not impact Statoil's financial statements materially.
- IFRS 13 *Fair Value Measurement*, issued in May 2011, is to be implemented prospectively upon adoption. Statoil has not identified material changes to the values of assets and liabilities measured at fair value in its financial statements as a consequence of IFRS 13.
- The amendments to IAS 19 *Employee Benefits*, issued in June 2011, introduce changes to pension related accounting and disclosure, but will not materially impact Statoil's financial statements upon adoption.
- The amendments *to* IAS 1 *Presentation of Financial Statements*, issued in June 2011, will not materially impact Statoil's presentation of Other comprehensive income (OCI).

- The amendments to IFRS 7 *Financial Instruments: Disclosures*, issued in December 2011, introduce new requirements for disclosure related to offsetting of financial assets and financial liabilities. Statoil will provide the relevant disclosure as applicable.
- The Improvements to IFRSs (2009 - 2011) issued in May 2012 will not materially impact Statoil's Consolidated financial statements upon adoption.

At the date of these Consolidated financial statements the following further standard and amendments applicable to Statoil have been issued but were not yet effective nor adopted by Statoil. Statoil has not yet determined its adoption date for the standard and amendments and is still evaluating their potential impact:

- IFRS 9 *Financial Instruments*, issued for the first part in November 2009 and for the second part in October 2010, covers the classification and measurement of financial assets and financial liabilities, respectively. IFRS 9 will be effective from 1 January 2015, and also entails amendments to various other IFRSs effective from the same date.
- The amendments to IAS 32 *Financial Instruments: Presentation*, issued in December 2011, and effective from 1 January 2014, clarifies the requirements for offsetting financial assets and financial liabilities in the financial statements.

Other standards, amendments and interpretations currently in issue but not yet effective are not expected to be relevant to Statoil Consolidated financial statements upon adoption.

Significant changes in accounting policies in the current period

With effect from 2012 Statoil changed its policy for classification in the balance sheet of short-term financial investments with less than three months to maturity from *Financial investments* to *Cash and cash equivalents*. At the same time, Statoil changed its policy for presentation of changes in current financial investments in the statement of cash flows from *Cash flows provided by operating activities* to *Cash flows used in investing activities*. The changes have been applied retrospectively in these Consolidated financial statements including the notes, and consequently an opening balance sheet as of 31 December 2010 (1 January 2011) has been included.

As part of its liquidity management, Statoil has gradually increased its use of short-term highly liquid investments, such as short-term debt securities and money market funds. This development, combined with relatively high levels of liquidity being maintained over time, has led Statoil to conclude that presenting money market funds and highly liquid investments with less than three months to maturity as part of *Cash and cash equivalents,* rather than *Financial investments*, better reflects Statoil's liquidity management policies and therefore provides more relevant information. In conjunction with the above change, Statoil also considers it more relevant to present changes in the remaining financial investments, i.e. excluding those that are now included under *Cash and cash equivalents*, as *Investing activities* in the statement of cash flows.

For further information see note 3 *Change in accounting policy* to these financial statements.

Basis of consolidation

Subsidiaries

The Consolidated financial statements include the accounts of Statoil ASA and its subsidiaries.

All intercompany balances and transactions, including unrealised profits and losses arising from Statoil's internal transactions, have been eliminated in full. Non-controlling interests (minority interests) are presented separately within equity in the balance sheet.

Jointly controlled assets, jointly controlled entities and associates

Interests in jointly controlled assets are recognised by including Statoil's share of assets, liabilities, income and expenses on a line-by-line basis. Interests in jointly controlled entities are accounted for using proportionate consolidation. Investments in companies in which Statoil does not have control or 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 jointly controlled assets

Indirect operating expenses such as personnel expenses are accumulated in cost pools. These costs are allocated to business areas and Statoil operated jointly controlled assets (licences) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets 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 jointly controlled assets 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. Quantitative thresholds related to reported revenue, net operating income and assets are also applied.

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 and chemical 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 revenue and cost of goods sold 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 revenue.

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%, 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, 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 7.5% 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.

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 the line item *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.

Capitalised exploration and evaluation expenditures, including expenditures to acquire mineral interests in oil and gas properties, related to wells that find proved reserves are transferred from Exploration expenditures and Acquisition costs - oil and gas prospects (*Intangible assets*) to Assets under development (*Property, plant and equipment*) at the time of sanctioning of the development project. For onshore wells where no sanction is required, the transfer of capitalised expenditures from *Intangible assets* to *Property, plant and equipment* occurs at the time when a well is ready for production.

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.

Assets classified as held for sale

Non-current assets are classified separately as held for sale in the balance sheet when their carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met only when the sale is highly probable, the asset is available for immediate sale in its present condition, and management is committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification. Liabilities directly associated with the assets classified as held for sale, and expected to be included as part of the sale transaction, are correspondingly also classified separately. Once classified as held for sale, property, plant and equipment and intangible assets are not subject to depreciation or amortisation. The net assets and liabilities of a disposal group classified as held for sale are measured at the lower of their carrying amount and fair value less cost to sell.

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 jointly controlled asset in which Statoil participates 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 *Bonds, bank loans and finance lease liabilities*, respectively. 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 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 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 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. Such offsetting of balances is reflected within *Trade and other receivables, Trade and other payables,* and *Derivative financial instruments* assets and liabilities, respectively.

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 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. Individual assets are grouped based on levels with separately identifiable and largely independent cash inflows. Normally, separate cash-generating units are individual oil and gas fields or plants. For offshore capitalised exploration expenditures and acquisition costs - oil and gas prospects, the cash-generating units are individual wells, while onshore, each unconventional shale play is considered a cash-generating unit.

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. 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 cash generating assets, 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 cash generating units 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 cash-generating unit, or group of units, to which the goodwill relates. Where the recoverable amount of the cash-generating unit, 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 shares 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 interest element of the defined benefit cost 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 expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognised in the statement of income as a part of the net periodic pension cost.

Periodic pension cost is accumulated in cost pools and allocated to business areas and Statoil operated jointly controlled assets (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 immediately when the benefits become vested or on a straight-line basis until the benefits become vested. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, 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 during the period in which the settlement or curtailment occurs.

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 cash generating unit whose assets are dedicated to that contract, and for which the economic benefits cannot be reliably separated from those of the cash generating unit, is included in impairment considerations for the applicable cash generating unit.

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 credit premium. 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 bid and ask 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 judgment 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.

Proportionate gain recognition when forming joint ventures by reducing shares in subsidiaries
There is a conflict in the accounting standards between the requirements of IAS 27 *Consolidated and Separate Financial Statements* and IAS 31 *Interests in Joint Ventures* / SIC-13 *Jointly Controlled Entities - Non-Monetary Contributions by Venturers* for gain recognition when forming joint ventures by reducing ownership shares in subsidiaries. Under the requirements of IAS 27, the sale of ownership interests in the wholly-owned entity would result in the loss of control of a subsidiary with gain recognition of 100% and the establishment of a new cost base at fair value for the retained partnership units. Under the requirements of IAS 31/SIC-13, the gain recognition would be the portion of the gain attributable to the equity interests of the buyers. In view of the inconsistency, Statoil has chosen as its accounting policy for sales transactions, when the substance of such a transaction is the establishment of a

joint venture, to account for such transactions under the provisions of IAS 31/SIC-13. Consequently, Statoil recognises a gain on such a sale for the portion attributable to the equity interests of the respective buyer.

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 and 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, 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, which affect the overall results. 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 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 what is referred to as 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 book value 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 moreover 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, and consequently in ensuring that the recoverable amount estimates' robustness where relevant is factored sufficiently into the impairment evaluations and reflected in the impairment or reversal of impairment recognised in the financial statements. 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 termination value of an asset.

Employee retirement plans. When estimating the present value of defined benefit pension obligations that represent a gross long-term liability in the balance sheet, and indirectly, the period's net pension expense in the 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, the expected return on 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 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, considering 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 both 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 and forward curves could materially impact the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in 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 Change in accounting policy

As stated in note 2 *Significant accounting policies*, with effect from 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 has been retrospectively applied in these Consolidated financial statements and the following tables show the effect of the changes in previous periods. All the restated comparable figures are also presented in the relevant notes.

CONSOLIDATED BALANCE SHEET

(in NOK billion)	As restated At 31 December 2011	2010	As earlier reported At 31 December 2011	2010
Financial investments	5.2	8.2	19.9	11.5
Cash and cash equivalents	55.3	33.8	40.6	30.5
Total	60.5	42.0	60.5	42.0

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK billion)	As restated For the year ended 31 December 2011	2010	As earlier reported For the year ended 31 December 2011	2010
Cash flows provided by operating activities	119.0	85.2	111.5	80.8
Cash flows used in investing activities	(84.9)	(79.3)	(88.7)	(76.5)
Cash flows provided by (used in) financing activities	(12.7)	(0.8)	(12.8)	(0.9)
Net increase (decrease) in cash and cash equivalents	21.4	5.1	10.0	3.4
Effect of exchange rate changes on cash and cash equivalents	(0.2)	0.3	(0.3)	0.4
Cash and cash equivalents at the beginning of the period (net of overdraft)	32.4	27.0	29.1	25.3
Cash and cash equivalents at the end of the period (net of overdraft)	53.6	32.4	38.8	29.1

8.1.4 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), Other and Fuel and Retail (FR; until 19 June 2012 when the segment was sold).

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 Statoil group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective Development and Production 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.

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 Other reporting segment includes activities within Global Strategy and Business Development, Technology, Projects and Drilling and the Corporate staffs and services.

Statoil reports its business through reporting segments which correspond to the operating segments, except for the operating segments DPI and DPNA which have been combined into one reporting segment, Development and Production International. This combination 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 eliminations section 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.

Segment data for the years ended 31 December 2012, 2011 and 2010 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 and intangible assets 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 2012							
Revenues third party and Other income	7.7	25.7	646.8	1.3	40.2	0.0	721.7
Revenues inter-segment	213.0	55.9	22.2	0.0	1.5	(292.6)	0.0
Net income (loss) from associated companies	0.1	1.2	0.4	0.0	0.0	0.0	1.7
Total revenues and other income	220.8	82.8	669.4	1.3	41.7	(292.6)	723.4
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	0.0	59.3
- Net impairment losses (reversals)	0.6	0.0	0.6	0.0	0.0	0.0	1.2
- Unrealised (gain) loss on commodity derivatives	1.4	0.0	1.8	0.0	0.0	0.0	3.2
- Exploration expenditure written off	0.8	2.3	0.0	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 and intangible assets	48.6	54.6	6.0	1.6	0.9	-	111.7

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

(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	25.1	564.1	1.0	70.8	0.0	668.9
Revenues inter-segment	204.2	44.8	45.7	0.0	2.9	(297.6)	0.0
Net income (loss) from associated companies	0.1	0.9	0.2	0.1	0.0	0.0	1.3
Total revenues and other income	212.2	70.8	610.0	1.1	73.7	(297.6)	670.2
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	0.0	50.2
- Net impairment losses (reversals)	0.0	(2.1)	3.3	0.0	0.0	0.0	1.2
- Unrealised (gain) loss on commodity derivatives	(5.6)	0.0	(3.6)	0.0	0.0	0.0	(9.2)
- Exploration expenditure written off	1.0	0.5	0.0	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 and intangible assets	41.5	84.3	4.7	1.6	1.5	-	133.6

(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 2010							
Revenues third party and Other income	4.1	8.4	452.6	1.4	62.3	0.0	528.8
Revenues inter-segment	166.6	41.9	40.5	2.2	3.6	(254.8)	0.0
Net income (loss) from associated companies	0.0	0.7	0.5	(0.1)	0.0		1.1
Total revenues and other income	170.7	51.0	493.6	3.5	65.9	(254.8)	529.9
Net operating income	115.7	12.6	6.1	0.6	2.4	(0.1)	137.3
Significant non-cash items recognised							
- Depreciation and amortisation	26.0	15.2	3.0	0.7	1.2	0.0	46.1
- Net impairment losses (reversals)	0.0	1.5	3.0	0.0	0.1	0.0	4.6
- Unrealised (gain) loss on commodity derivatives	(1.8)	0.0	4.3	0.0	0.0	0.0	2.5
- Exploration expenditure written off	1.4	1.5	0.0	0.0	0.0	0.0	2.9
Investments in associated companies	0.1	5.1	3.6	0.2	-	-	9.0
Non-current segment assets	188.2	137.3	55.2	3.0	11.1	-	394.8
Non-current assets, not allocated to segments							47.0
Total non-current assets							450.8
Assets classified as held for sale	-	44.9	-	-	-	-	44.9
Additions to PP&E and intangible assets	31.9	44.2	7.7	1.0	0.8	-	85.6

See note 12 *Property, plant and equipment* and note 13 *Intangible assets* for information on impairments recognised.

See note 5 *Acquisitions and dispositions* for information on gains and losses on transactions that affect the different segments.

Geographical areas

Statoil has business operations in 35 countries. When attributing revenues from third parties to the country of the legal entity executing the sale, Norway constitutes 77% and the USA 15%.

Non-current assets by country

(in NOK billion)	2012	At 31 December 2011	2010
Norway	258.7	249.2	240.0
USA	134.6	112.6	53.7
Angola	42.5	43.6	29.1
Brazil	23.2	26.0	37.0
Canada	17.2	17.3	24.5
Azerbaijan	16.7	17.8	17.3
UK	11.1	8.9	7.5
Algeria	8.7	9.6	9.3
Other countries	22.3	24.5	30.3
Total non-current assets* and assets classified as held for sale	535.0	509.5	448.7

*Excluding deferred tax assets, pension assets and non-current financial assets.

Revenues by product type

(in NOK billion)	For the year ended 31 December 2012	2011	2010
Crude oil	368.4	315.1	254.0
Refined products	140.9	128.8	107.5
Gas	118.6	99.0	84.8
Natural gas liquids	65.8	62.3	49.6
Other	12.0	40.4	31.1
Total revenues	705.7	645.6	527.0

8.1.5 Acquisitions and dispositions

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 Norwegian continental shelf (NCS) for a total consideration of NOK 8.6 billion. The consideration includes a cash payment of NOK 7.1 billion, a contingent element and the responsibility for tax payments for the period between 1 January 2012 and the transaction date. The contingent element relates to production in a four year period and is capped at NOK 0.6 billion. A gain of NOK 7.5 billion has been recognised in the Development and Production Norway (DPN) segment in the second quarter 2012 and presented as *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 includes 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 has been 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.

Agreement with Wintershall to sell interest in exploration and production licences on the NCS

On 21 October 2012 Statoil entered into an agreement with Wintershall to sell its ownership interests in certain licences on the NCS. Wintershall will pay a cash consideration of NOK 7.5 billion (USD 1.4 billion). In addition, Statoil will receive a 15% working interest in the Edvard Grieg licence and a contingent consideration of up to NOK 0.6 billion (USD 0.1 billion). Statoil will continue to consolidate the proportionate share (current ownership share) of the revenues and expenditures until the date of closing of the transaction. The consideration will be adjusted for the activity after 1 January 2013 and for working capital at the transaction date. The transaction is subject to approvals from the Norwegian Ministry of Petroleum and Energy and the Norwegian Ministry of Finance, which includes approval of the transfer of operatorship on the Brage licence to Wintershall. The transaction will be recognised in the DPN segment at the time of closing, which is expected in the second half of 2013. Statoil expects to recognise a gain from the transaction estimated to be between NOK 6 and 7 billion, to be adjusted for activity between 1 January 2013 and the transaction date. The transaction will be tax exempt under rules in the Norwegian Petroleum Tax system and the estimated gain includes a release of related deferred tax liabilities.

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 will be the operator of the licences and hold a 100% working interest in these mineral right leases. The transaction has been accounted for as an asset acquisition within the Development and Production International (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 are 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 has been accounted for as a business combination using the acquisition method, where the acquired assets and liabilities have been measured at fair value at the date of acquisition and it 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 will not be deductible for tax purposes. The 2011 Consolidated financial statements include 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 have been set up as production sharing agreements (PSAs) in which the national oil company of Angola, Sonangol, participates 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 includes 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 continues 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 is 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 includes a release of deferred tax liabilities related to the tax exempted portion of the transaction. The transaction was recognised in the Marketing, Processing and Renewable Energy segment and presented as *Other income*.

2010

Acquisition of mineral right leases in Eagle Ford shale formation, Texas US
On 8 October 2010 Statoil signed a Purchase and Sale agreement with Talisman Energy Inc. and Enduring Resources LLC under which Statoil, through a 50/50 joint venture with Talisman Energy Inc., acquired mineral right leases covering 67,000 net acres in the Eagle Ford shale formation in Southwest Texas. The transaction was accounted for as an asset acquisition. Total consideration for Statoil's share was NOK 5.4 billion (USD 0.9 billion). The transaction was completed on 8 December 2010 and has been recognised in the DPI segment.

Sale of interests in Kai Kos Dehseh, Canada
On 21 November 2010 Statoil entered into an agreement with PTT Exploration and Production (PTTEP) to form a joint venture relating to the Kai Kos Dehseh oil sands project, which reduced Statoil's ownership interest from 100% to 60%. The Kai Kos Dehseh oil sands project in Alberta, Canada, is legally organised as a partnership and through the sale, PTTEP acquired 40% of the partnership interests. Following the transaction, which was closed on 21 January 2011, the Kai Kos Dehseh oil sands activity is accounted for as a jointly controlled entity using proportionate consolidation.

PTTEP paid a total consideration of NOK 13.2 billion. A gain of NOK 5.5 billion has been recognised in accordance with the provisions of IAS 31/SIC 13 (see note 2 *Significant accounting policies*) and presented as *Other income*. The transaction was recognised in the DPI segment in the first quarter 2011.

Sale of interests in Peregrino assets, Brazil
On 21 May 2010 Statoil entered into an agreement to form a joint venture with Sinochem Group by selling 40% of the Peregrino offshore heavy-oil field in Brazil. Following closure of the transaction Statoil holds a 60% ownership share and together with Sinochem jointly controls the Peregrino assets. Statoil remained operator of the field, which started production in April 2011. Governmental approvals were received in April 2011 and the transaction was closed on 14 April 2011.

Sinochem Group paid a total of NOK 19.5 billion in cash for the 40% share of the net assets through acquisition of shares in various Statoil entities. The gain from the transaction of NOK 8.8 billion was recognised in accordance with the provisions of IAS 31/SIC 13 and presented as *Other income*. The transaction was recognised in the DPI segment in the second quarter 2011.

Assets classified as held for sale
The carrying amounts of assets and liabilities classified as held for sale in the Consolidated balance sheet at year end 2010 are related to Statoil's agreements with PTTEP for the sale of a 40% ownership interest in the Kai Kos Dehseh oil sands project and the agreement with Sinochem Group for the sale of a 40% ownership in the Peregrino offshore heavy-oil field.

8.1.6 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 all 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 our total market risk. This approach allows us to reduce the number of hedging transactions and thereby reduce transaction costs and avoid sub-optimisation.

An important element in the risk management approach is the use of centralised trading mandates requiring all major strategic transactions 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 28 *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 and is monitored every day against established mandates as defined by the governing policies. 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 in crude and refined products swaps markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, NASDAQ OMX Oslo (formerly named Nordpool) 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 28 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Currency risk
In addition to price developments, Statoil's operating results and cash flows are affected by foreign currency fluctuations in the most significant currencies (NOK, EUR and GBP) against USD.

Statoil manages its currency risk from operations with USD as the basis currency. Foreign exchange risk is managed at corporate level in accordance with given policies and mandates. In the present Euro-zone uncertainty, Statoil has established processes to be prepared for different outcomes.

Statoil's operating cash flows derived 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 currrency 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
With regards to interest rate risk, Statoil manages its interest rates exposure on its long-term issued debt mainly by converting the cash flows from fixed coupon payments into floating rate interest payments through the use of interest rate swaps.

Statoil aims to diversify sources of funding, and to achieve lower expected funding costs over time.

Bonds are normally issued at fixed rates in a variety of local currencies (among others JPY, EUR, GBP and USD). These bonds are normally converted to floating USD bonds by using interest rate and currency swaps. For more detailed information about Statoil's long-term debt portfolio see note 20 *Bonds, bank loans and finance lease liabilities.*

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 high focus and attention on credit and liquidity risk throughout its entire organisation. In order to secure necessary financial flexibility, which includes meeting the financial obligations, Statoil maintains what it believes to be a conservative liquidity management policy. To secure financial flexibility and identify future long-term financing needs, Statoil carries out three-year cash forecasts at least monthly.

Statoil's operating cash flows are significantly impacted by, among other things, the volatility in the oil and gas prices as well as production volumes. During 2012 Statoil's overall liquidity position remained strong.

The main cash outflows are the annual dividend payment and Norwegian Petroleum Tax payments 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.

Current funding needs will normally be covered by using 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 provides secure access to funding, supported by best available short-term rating and 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 an average maturity of approximately nine years.

For more information about Statoil's non-current financial liabilities see note 20 *Bonds, bank loans and finance lease liabilities.*

The table below shows a maturity profile, based on undiscounted contractual cash flows, for Statoil's financial liabilities.

	At 31 December	
(in NOK billion)	2012	2011
Due within 1 year	(102.8)	(111.1)
Due between 1 and 2 years	(28.6)	(31.7)
Due between 3 and 4 years	(21.0)	(33.7)
Due between 5 and 10 years	(44.9)	(48.7)
Due after 10 years	(55.0)	(55.2)
Total specified	(252.3)	(280.4)

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 our 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 counter-party'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 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 asset	2.5	63.7	33.2	3.6
At 31 December 2011				
Investment grade, rated A or above	1.0	31.2	19.4	3.5
Other investment grade	0.0	35.8	13.3	2.3
Non-investment grade or not rated	0.6	27.7	0.0	0.1
Total financial asset	1.6	94.7	32.7	5.9

At 31 December 2012, NOK 12.4 billion of cash was held as collateral to mitigate a portion of Statoil's credit exposure. At 31 December 2011 NOK 10.8 billion was held as collateral. The collateral is cash received as a security to mitigate credit exposure related to positive fair values on interest rate swaps, cross currency interest rate swaps and foreign currency 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. The collateral received reduces the credit exposure in the Derivative financial instruments presented in the table above.

8.1.7 Remuneration

(in NOK billion, except average number of man-labour years)	For the year ended 31 December 2012	2011	2010
Salaries	22.7	21.1	19.8
Pension costs	(0.6)	3.8	4.1
Payroll tax	3.3	3.3	3.0
Other compensations and social costs	2.8	2.5	2.2
Total payroll costs	28.2	30.7	29.1
Average number of man-labour years	26,728	29,378	28,396

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 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 21 *Pensions*.

Compensation to the board of directors (BoD) and the corporate executive committee (CEC)
The remuneration to members of the BoD and the CEC during the year was as follows:

(in NOK million)	For the year ended 31 December 2012	2011	2010
Current employee benefits	81.1	59.4	49.9
Post-employment benefits	13.6	12.0	11.4
Other non-current benefits	0.1	0.1	0.1
Share based payment benefits	1.3	1.0	0.8
Total	96.1	72.5	62.2

At 31 December 2012, 2011 and 2010 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 0.5 billion, NOK 0.5 billion and NOK 0.4 billion related to the 2012, 2011 and 2010 programs, respectively. For the 2013 program (granted in 2012) the estimated compensation expense is NOK 0.6 billion. At 31 December 2012 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 1.1 billion.

8.1.8 Other expenses

Auditor's remuneration

(in NOK million, excluding VAT)	For the year ended 31 December 2012	2011	2010
Audit fee	44	63	65
Audit related fee	9	7	14
Tax fee	2	0	0
Other service fee	2	3	0
Total	57	73	79

In addition to the figures in the table above, the audit fees and audit-related fees related to Statoil-operated licences amount to NOK 7 million, NOK 9 million and NOK 9 million for 2012, 2011 and 2010, respectively.

Research and development expenditures
Research and development (R&D) expenditures were NOK 2.8 billion, NOK 2.2 billion and NOK 2.0 billion in 2012, 2011 and 2010, 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.

8.1.9 Financial items

(in NOK billion)	For the year ended 31 December 2012	2011 (restated)	2010 (restated)
Foreign exchange gains (losses) derivative financial instruments	2.1	1.6	(1.7)
Other foreign exchange gains (losses)	(1.3)	(2.2)	(0.2)
Net foreign exchange gains (losses)	0.8	(0.6)	(1.9)
Dividends received	0.1	0.1	0.1
Gains (losses) financial investments	0.6	(0.4)	0.8
Interest income financial investments	0.6	0.5	0.3
Interest income non-current financial receivables	0.1	0.1	0.1
Interest income current financial assets and other financial items	0.4	1.9	1.9
Interest income and other financial items	1.8	2.2	3.2
Interest expense bonds and bank loans and net interest on related derivatives	(2.5)	(2.2)	(2.1)
Interest expense finance lease liabilites	(0.5)	(0.6)	(0.2)
Capitalised borrowing costs	1.2	0.9	1.0
Accretion expense asset retirement obligations	(3.0)	(2.8)	(2.6)
Gains (losses) derivative financial instruments	3.0	6.9	2.6
Interest expense current financial liabilities and other finance expense	(0.7)	(1.8)	(0.5)
Interest and other finance expenses	(2.5)	0.4	(1.8)
Net financial items	0.1	2.0	(0.5)

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 28 *Financial instruments: fair value measurement and sensitivity analysis of market risk.*

In the above table the line item Interest expense bonds and bank loans and net interest on related derivatives for 2012 primarily includes interest expenses of NOK 4.8 billion from the financial liabilities at amortised cost category, partly offset by net interest on related derivatives of NOK 2.5 billion from the held for trading category. The line item Gains (losses) derivative financial instruments primarily includes fair value gains of NOK 2.9 billion from the held for trading category. In addition a net exchange gain of NOK 4.2 billion from the held for trading category is included in the line item Foreign exchange gains (losses) derivative financial instruments. Correspondingly, the line item Interest expense bonds and bank loans and net interest on related derivatives for 2011 primarily included interest expenses of NOK 5.6 billion from the financial liabilities at amortised cost category, partly offset by net interest on related derivatives of NOK 2.5 billion from the held or trading category. The line item Gains (losses) derivative financial instruments primarily included fair value gains of NOK 6.8 billion from the held for trading category. In addition a net exchange gain of NOK 3.3 billion from the held for trading category were included in the line item Foreign exchange gains (losses) derivative financial instruments.

In 2012 an impairment loss of NOK 2.1 billion recognised for an investment classified in the available for sale category is included in Interest income current financial assets and other financial items.

As stated in note 3 *Change in accounting policy*, with effect from 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. As a consequence, certain reclassifications of related foreign currency effects between the line items Net foreign exchange gains (losses) and Interest and other financial items have been made; however, there is no impact on *Net financial items*.

8.1.10 Income taxes

Significant components of income tax expense

	For the year ended 31 December		
(in NOK billion)	2012	2011	2010
Current income tax expense in respect of current year	138.1	131.5	97.5
Prior period adjustments	(0.5)	0.2	(0.7)
Current income tax expense	137.6	131.7	96.8
Origination and reversal of temporary differences	0.3	7.0	2.4
Recognition of previously unrecognised deferred tax assets	(3.0)	(3.1)	0.0
Change in tax regulations	2.3	0.0	0.0
Prior period adjustments	0.0	(0.2)	0.0
Deferred tax expense	(0.4)	3.7	2.4
Income tax expense	137.2	135.4	99.2

Reconciliation of nominal statutory tax rate to effective tax rate

(in NOK billion)	For the year ended 31 December 2012	2011	2010
Income before tax	206.7	213.8	136.8
Calculated income tax at statutory rate*	62.9	64.0	43.1
Calculated Norwegian Petroleum tax**	87.4	84.9	61.5
Tax effect of uplift**	(5.3)	(5.1)	(5.0)
Tax effect of permanent differences	(6.3)	(5.7)	0.7
Recognition of previously unrecognised deferred tax assets***	(3.0)	(3.1)	0.0
Change in tax regulations	2.3	0.0	0.0
Prior period adjustments	(0.5)	0.0	(0.7)
Other items	(0.3)	0.4	(0.4)
Income tax expense	137.2	135.4	99.2
Effective tax rate	66.4%	63.3%	72.5%

* The weighted average of statutory tax rates was 30.4% in 2012, 29.9% in 2011 and 31.5% in 2010. The increase from 2011 to 2012 was principally due to a change in the geographic mix of income, with a higher proportion of income in 2012 arising in jurisdictions subject to relatively higher tax rates. The decrease from 2010 to 2011 was also due to such changes.

** When computing the petroleum tax of 50% on income from the Norwegian continental shelf, a tax-free allowance, or uplift, is granted at a rate of 7.5% per year. 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 2012 and 2011 unrecognised uplift credits amounted to NOK 17.5 billion and NOK 15.1 billion, respectively.

*** An amount of NOK 3.0 billion of previously unrecognised deferred tax assets was recognised in 2012. The recognition of the deferred tax assets is based on the expectation that sufficient taxable income will be available through reversals of taxable temporary differences and future taxable income. In 2011, previously unrecognised deferred tax assets of NOK 3.1 billion was recognised.

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 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)
Deferred tax at 31 December 2011								
Deferred tax assets	11.0	9.2	0.0	55.4	6.6	0.0	10.4	92.6
Deferred tax liabilities	0.0	(127.7)	(16.3)	0.0	0.0	(18.4)	(7.0)	(169.4)
Net asset (liability) at 31 December 2011	11.0	(118.5)	(16.3)	55.4	6.6	(18.4)	3.4	(76.8)

Changes in net deferred tax liability during the year were as follows:

(in NOK billion)	2012	2011	2010
Net deferred tax liability at 1 January	76.8	76.2	74.4
Charged (credited) to the Consolidated statement of income	(0.4)	3.7	2.4
Other comprehensive income pensions	1.7	(2.0)	0.0
Translation differences and other	(0.8)	(1.1)	(0.6)
Net deferred tax liability at 31 December	77.3	76.8	76.2

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)	2012	2011
Deferred tax assets	3.9	5.7
Deferred tax liabilities	(81.2)	(82.5)

Deferred tax assets are recognised based on the expectation that sufficient taxable income will be available through reversal of taxable temporary differences or future taxable income. At year end 2012 the net deferred tax assets are primarily recognised in the USA and Angola, while at year end 2011 the deferred tax assets were primarily recognised in Norway.

Unrecognised deferred tax assets

	At 31 December	
(in NOK billion)	2012	2011
Deductible temporary differences	1.0	3.7
Tax losses carried forward	7.8	9.0

Approximately 43% of the unrecognised losses carry-forwards may be carried forward indefinitely. The majority of the remaining part of the unrecognised tax losses expire after 2019. 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.

8.1.11 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 thousands)	2012	2011	2010
Weighted average number of ordinary shares	3,181,546	3,182,113	3,182,575
Weighted average number of ordinary shares, diluted	3,190,221	3,190,044	3,189,689

8.1.12 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 2011	23.2	751.4	53.6	16.9	97.7	942.8
Additions and transfers	1.3	100.0	7.8	1.5	6.7	117.3
Disposal assets 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	817.3	56.6	7.4	99.0	998.7
Accumulated depreciation and impairment losses at 31 December 2011	(15.5)	(470.0)	(40.7)	(7.2)	(1.8)	(535.2)
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)	(502.1)	(39.9)	(2.9)	(2.0)	(559.6)
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		

(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 2010	22.1	678.2	55.5	16.5	76.1	848.4
Transfered from assets classified as held for sale	0.0	0.0	0.0	0.0	32.5	32.5
Additions and transfers	1.9	98.4	1.3	0.8	2.0	104.4
Additions from business combination	0.1	6.3	0.0	0.0	1.2	7.6
Disposals assets at cost	(1.2)	(38.7)	(3.4)	(0.1)	(13.6)	(57.0)
Effect of changes in foreign exchange	0.3	7.2	0.2	(0.3)	(0.5)	6.9
Cost at 31 December 2011	23.2	751.4	53.6	16.9	97.7	942.8
Accumulated depreciation and impairment losses at 31 December 2010	(14.3)	(437.6)	(36.7)	(6.6)	(1.6)	(496.8)
Additions and transfers	0.0	0.0	0.0	0.0	(2.2)	(2.2)
Depreciation	(1.4)	(45.6)	(2.2)	(0.7)	(0.2)	(50.1)
Impairment losses	(0.5)	(0.3)	(3.5)	(0.1)	0.0	(4.4)
Reversal of impairment losses	0.0	0.5	0.0	0.0	2.0	2.5
Accumulated depreciation and impairment disposed assets	0.9	16.4	1.9	0.1	0.0	19.3
Effect of changes in foreign exchange	(0.2)	(3.4)	(0.2)	0.1	0.2	(3.5)
Accumulated depreciation and impairment losses at 31 December 2011	(15.5)	(470.0)	(40.7)	(7.2)	(1.8)	(535.2)
Carrying amount at 31 December 2011	7.7	281.4	12.9	9.7	95.9	407.6
Estimated useful lives (years)	3 - 20	*	15-20	20 - 33		

* Depreciation according to unit of production method, see note 2 *Significant accounting policies*.

In 2012 and 2011 capitalised borrowing costs amounted to NOK 1.2 billion and NOK 0.9 billion, respectively.

The carrying amount of assets transferred to *Property, plant and equipment* from *Intangible assets* in 2012 and 2011 amounted to NOK 7.0 billion and NOK 3.7 billion, respectively.

In 2011 Statoil recognised impairment losses of NOK 3.8 billion related to refinery assets in the MPR segment. The basis for the impairment losses was value in use estimates triggered by decreasing expectations on refining margins. The impairment losses have been presented as *Depreciation, amortisation and net impairment losses*.

In 2011 Statoil recognised a reversal of impairment losses of NOK 2.6 billion related to assets in the Gulf of Mexico in the DPI segment. The basis for the reversal was value in use estimates triggered by changes in cost estimates and market conditions.

In 2010 Statoil recognised impairment losses of NOK 2.9 billion related to refinery assets in the MPR segment. The basis for the impairment losses was value in use estimates triggered by decreasing expectations on refining margins. In 2010 Statoil also recognised an impairment loss of NOK 1.6 billion related to a gas development project in the DPI segment. The basis for the impairment loss was reduced value in use estimate mainly driven by project delays, changes in certain cost estimates and market conditions.

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 costs to sell and estimated value in use. The base discount rate used 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. Please see note 2 *Significant accounting policies* for further information regarding impairment on property, plant and equipment.

8.1.13 Intangible assets

(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	2.8	93.8
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	2.4	88.0
Accumulated amortisation and impairment losses at 31 December 2011			(0.4)	(0.7)	(1.1)
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	(0.4)	(0.4)
Carrying amount at 31 December 2012	18.6	57.3	9.7	2.0	87.6

(in NOK billion)	Exploration expenditures	Acquisition costs - oil and gas prospects	Goodwill	Other	Total
Cost at 31 December 2010	15.3	23.0	4.4	2.4	45.1
Transfered from assets classified as held for sale	0.9	11.5	0.0	0.0	12.4
Additions	6.4	7.8	0.0	0.3	14.5
Additions through business combination	0.0	24.1	6.8	0.0	30.9
Disposals at cost	(0.5)	(5.0)	0.0	0.0	(5.5)
Transfers	(2.2)	(1.5)	0.0	0.0	(3.7)
Expensed exploration expenditures previously capitalised	(0.7)	(0.8)	0.0	0.0	(1.5)
Effect of changes in foreign exchange	0.5	0.8	0.2	0.1	1.6
Cost at 31 December 2011	19.7	59.9	11.4	2.8	93.8
Accumulated amortisation and impairment losses at 31 December 2010			(0.4)	(1.5)	(1.9)
Amortisation and impairment losses for the year			0.0	(0.2)	(0.2)
Reversal of impairment			0.0	0.9	0.9
Effect of changes in foreign exchange			0.0	0.1	0.1
Accumulated amortisation and impairment losses at 31 December 2011			(0.4)	(0.7)	(1.1)
Carrying amount at 31 December 2011	19.7	59.9	11.0	2.1	92.7

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 impairments are based on value in use estimates triggered by changes in reserve estimates, cost estimates and market conditions. See note 12 *Property, plant and equipment* for further information on the basis for impairment assessments.

The table below shows the ageing of capitalised exploration expenditures.

(in NOK billion)	Amount capitalised
Less than one year	7.1
Between one and five years	10.1
Between five and nine years	1.4
Total	18.6

The table below shows the components of the exploration expenses.

	For the year ended 31 December		
(in NOK billion)	2012	2011	2010
Exploration expenditure	20.9	18.8	16.8
Expensed exploration expenditures previously capitalised	3.1	1.5	2.9
Capitalised exploration	(5.9)	(6.5)	(3.9)
Exploration expenses	18.1	13.8	15.8

8.1.14 Non-current financial assets and prepayments

	At 31 December	
(in NOK billion)	2012	2011
Bonds	8.9	8.0
Listed equity securities	4.9	4.5
Non-listed equity securities	1.2	2.9
Financial investments	15.0	15.4

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-listed equity securities are classified as available for sale assets and changes in fair value are recognised in *Other comprehensive income*, except for impairment losses which are recognised in the Consolidated statement of income.

	At 31 December	
(in NOK billion)	2012	2011
Financial receivables interest bearing	2.5	1.6
Prepayments and other non-interest bearing receivables	2.4	1.7
Prepayments and financial receivables	4.9	3.3

Financial receivables interest bearing primarily relate to project financing of subcontractors and activity in associated companies. The carrying amount of non-current financial receivables and current financial receivables approximate fair value.

8.1.15 Inventories

(in NOK billion)	At 31 December 2012	2011
Crude oil	13.7	16.3
Petroleum products	9.8	8.9
Other	1.8	2.6
Inventories	25.3	27.8

8.1.16 Trade and other receivables

(in NOK billion)	At 31 December 2012	2011
Trade receivables	55.3	86.5
Current financial receivables	1.0	1.6
Joint venture receivables	6.9	5.9
Associated companies and other related party receivables	0.5	0.7
Total financial trade and other receivables	63.7	94.7
Non-financial trade and other receivables	10.3	9.1
Trade and other receivables	74.0	103.8

For more information about the credit quality of Statoil's counterparties see note 6 *Financial risk management*. For currency sensitivities see note 28 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

8.1.17 Current financial investments

		At 31 December	
(in NOK billion)	2012	2011 (restated)	2010 (restated)
Bonds	1.0	0.5	1.1
Treasury bills and commercial papers	13.9	4.7	7.1
Financial investments	14.9	5.2	8.2

Current financial investments at 31 December 2012 are classified as held for trading, except for NOK 5.4 billion related to investment portfolios which are held by Statoil's captive insurance company and accounted for using the fair value option. The corresponding balances at 31 December 2011 and 2010 were NOK 5.1 and NOK 6.2 billion, respectively.

8.1.18 Cash and cash equivalents

(in NOK billion)	2012	At 31 December 2011 (restated)	2010 (restated)
Cash at bank available	7.3	10.4	11.1
Time deposits	21.4	24.1	13.0
Money market funds	2.8	6.5	1.6
Treasury bills and commercial papers	31.4	8.2	1.7
Restricted cash, including collateral deposits	2.3	6.1	6.4
Cash and cash equivalents	65.2	55.3	33.8

Restricted cash at 31 December 2012 includes collateral deposits of NOK 1.9 billion related to trading activities. Corresponding collateral deposits at 31 December 2011 was NOK 1.8 billion. 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.

For information about the bank overdraft, please see note 24 *Bonds, bank loans, commercial papers and collateral liabilities.*

8.1.19 Shareholders' equity

At 31 December 2012 and 2011, 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 6.50 in 2012, NOK 6.25 in 2011 and NOK 6.00 in 2010. A dividend of NOK 6.75 per share, amounting to a total dividend of NOK 21.5 billion, will be proposed at the annual general meeting in May 2013. The proposed dividend is not recognised as a liability in the Consolidated financial statements.

Retained earnings available for distribution of dividends at 31 December 2012 are limited to the retained earnings of the parent company, net of deferred tax assets, based on Norwegian accounting principles and legal regulations and amounted to NOK 196.6 billion (before provisions for the proposed dividend of NOK 21.5 billion). This differs from *Retained earnings* of NOK 270.8 billion in the Consolidated statement of changes in equity. Retained earnings available for distribution of dividends at 31 December 2011 amounted to NOK 153.3 billion (before provisions for proposed dividend of NOK 20.7 billion for the year ended 31 December 2011).

During 2012 a total of 3,278,561 treasury shares were purchased for NOK 0.5 billion. In 2011 a total of 2,931,346 treasury shares were purchased for NOK 0.4 billion. At 31 December 2012 Statoil had 8,675,317 treasury shares and at 31 December 2011 7,931,347 treasury shares, all of which are related to Statoil's share saving plan.

8.1.20 Bonds, bank loans and finance lease liabilities

Capital management

The main objectives of Statoil's capital management policy is 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 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 in total NOK 7.3 billion and NOK 6.9 billion for 2012 and 2011, respectively), balances related to the SDFI (a decrease of NOK 1.2 billion and NOK 1.4 billion for 2012 and 2011, respectively) and project financing exposure that does not correlate to the underlying exposure (a decrease of NOK 0.3 billion and NOK 0.4 billion for 2012 and 2011, respectively). CE is defined as Statoil's total equity (including non-controlling interests) and ND.

(in NOK billion)	At 31 December 2012	2011
Net debt adjusted (ND)	45.1	76.0
Capital employed adjusted (CE)	365.0	361.2
Net debt to capital employed (ND/CE)	12.4%	21.1%

Bonds, bank loans and finance lease liabilities

Financial liabilities 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	
	2012	2011	2012	2011	2012	2011
Unsecured bonds						
US dollar (USD)	4.52	4.92	69.9	65.5	80.2	74.8
Euro (EUR)	4.99	4.99	18.4	19.5	22.8	23.1
Japanese yen (JPY)	-	1.66	-	0.4	-	0.4
Great Britain Pound (GBP)	6.71	6.71	9.2	9.5	13.8	13.2
Total			97.5	94.9	116.8	111.5
Unsecured loans						
US dollar (USD)	0.47	0.74	2.4	5.9	2.5	6.0
Norwegian kroner (NOK)	-	4.04	-	4.0	-	4.0
Japanese yen (JPY)	4.30	1.65	0.7	0.6	0.7	0.6
Secured bank loans						
US dollar (USD)	4.33	3.48	0.4	0.5	0.4	0.5
Other currencies	3.57	3.80	0.1	0.1	0.1	0.1
Finance lease liabilities			5.6	12.0	5.6	12.0
Other liabilities			-	0.8	-	0.8
Total			9.2	23.9	9.3	24.0
Total financial liabilities			106.7	118.8	126.1	135.5
Less current portion			5.7	7.2	5.9	7.2
Bonds, bank loans and finance lease liabilities			101.0	111.6	120.2	128.3

On 21 November 2012 Statoil issued USD 0.6 billion of bonds maturing in January 2018 and USD 1.1 billion of bonds maturing in January 2023. On 23 November 2012 Statoil reopened existing bonds maturing in November 2041 and issued USD 0.3 billion of bonds with the same maturity. The registered bonds were issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the Securities and Exchange Commission (SEC) in the USA.

Unsecured bonds amounting to NOK 69.9 billion are denominated in USD and unsecured bonds amounting to NOK 27.6 billion are swapped into USD. The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 28 *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 the pledging of assets to secure future 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 certain projects.

Statoil has 30 unsecured bond agreements outstanding which 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 96.0 billion at the 31 December 2012 closing rate.

For more information about the revolving credit facility, maturity profile for undiscounted cash flows and interest rate risk management, see note 6 *Financial risk management*.

Maturity profile bonds, bank loans and finance lease liabilities

(in NOK billion)	At 31 December 2012	2011
Year 2 and 3	19.1	21.3
Year 4 and 5	10.8	21.8
After 5 years	71.1	68.5
Total repayment	101.0	111.6
Weighted average maturity (year)	9	9
Weighted average annual interest rate (%)	4.74	4.84

More information regarding finance lease liabilities is provided in note 25 *Leases*.

8.1.21 Pensions

The Norwegian companies in the Statoil group are subject to the Mandatory Company Pensions Act, and their pension schemes follow 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 employees of Statoil ASA and Statoil Kapitalforvaltning ASA. 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 will be 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.

During 2012 a curtailment gain of NOK 4.3 billion has been 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. Employees remain entitled to the early retirement benefits available under the national Norwegian AFP plan. 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. The combined early retirement commitment was accounted for as one defined benefit plan, and consequently the discontinuation of the gratuity part was not regarded as a termination for the AFP part of the plan.

The present values of the projected 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 2012 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 21.9 year yield curve which matches the duration of Statoil's payment portfolio for earned benefits. Previously the discount rate was based on government bonds, as the market for high quality corporate bonds in Norway was assessed not to be sufficiently deep. The updated assessment of the Norwegian market for covered bonds (OMF) has, however, led Statoil to conclude that it is appropriate to determine the discount rate for pension obligations by reference to market yields on covered bonds.

Social security tax is calculated based on a pension plan's net funded status. Social security tax is included in the projected 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 Statement of income as pension cost for the period.

Net pension cost

	For the year ended 31 December		
(in NOK billion)	2012	2011	2010
Current service cost	3.8	3.6	3.5
Interest cost	2.2	2.7	2.7
Expected return on plan assets	(2.5)	(2.9)	(2.7)
Losses (gains) from curtailment or settlement	(4.3)	0.0	0.0
Actuarial (gains) losses related to termination benefits	0.0	0.1	0.2
Defined benefit plans	(0.8)	3.5	3.7
Defined contribution plans	0.2	0.2	0.2
Multi-employer plans	0.0	0.1	0.2
Total net pension cost	(0.6)	3.8	4.1

Pension cost includes associated social security tax and is partly charged to partners of Statoil operated licences.

(in NOK billion)	2012	2011
Projected benefit obligations (PBO)		
At 1 January	75.0	67.8
Current service cost	3.8	3.6
Interest cost	2.2	2.7
Actuarial losses (gains)	(3.4)	2.9
Benefits paid	(1.8)	(1.7)
Losses (gains) from curtailment or settlement	(4.7)	0.0
Acquisition and sale	(2.4)	(0.1)
Foreign currency translation	0.0	(0.2)
At 31 December	68.7	75.0
Fair value of plan assets		
At 1 January	51.9	51.0
Expected return on plan assets	2.5	2.9
Actuarial gains (losses)	1.9	(4.5)
Company contributions (including social security tax)	4.2	3.3
Benefits paid	(0.7)	(0.5)
(Losses) gains from curtailment or settlement	(0.1)	0.0
Acquisition and sale	(2.2)	(0.1)
Foreign currency translation	0.0	(0.2)
At 31 December	57.5	51.9
Net benefit liability at 31 December	11.2	23.1
Represented by:		
Asset recognised as non-current pension assets	9.4	3.9
Liability recognised as non-current pension liabilities	20.6	27.0
PBO specified by funded and unfunded pension plans	68.7	75.0
Funded	48.1	48.0
Unfunded	20.6	27.0
History of experience (gains) and losses		
Experience actuarial (gains) losses to the PBO	4.0	3.1
Experience actuarial (gains) losses to the plan assets	(1.9)	4.5
Actual return on assets	4.4	(1.6)

The tables above for PBO 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)

(in NOK billion)	For the year ended 31 December 2012	2011	2010
Net actuarial losses (gains) recognised during the year	(5.3)	7.4	0.3
Actuarial losses (gains) related to currency effects on net obligation and foreign exhange translation	(0.2)	0.0	(0.3)
Recognised directly in OCI during the year	5.5	(7.4)	0.0
Cumulative actuarial losses (gains) recognised directly in OCI net of tax	11.6	16.3	10.9

The net actuarial gain for 2012 is mainly related to an updated assessment of the appropriate discount rate to be used for pension obligations in Norway.

In the table above, Actuarial losses (gains) related to currency effects on net obligation relate to the translation of the net pension obligation in NOK to the functional currency USD for the parent company, Statoil ASA. Foreign exchange translation relates to the translation of the net pension obligation from the functional currency USD to Statoil's presentation currency NOK.

	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	
	2012	2011	2012	2011
Discount rate	3.25	4.25	3.75	3.25
Expected return on plan assets	4.75	5.75	4.50	4.75
Rate of compensation increase	3.00	4.00	3.25	3.00
Expected rate of pension increase	2.00	2.75	1.75	2.00
Expected increase of social security base amount (G-amount)	2.75	3.75	3.00	2.75
Average remaining service period in years			15	15

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 not significant to the consolidated pension assets and liabilities.

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. Expected attrition at 31 December 2011 was 2.2%, 2.0%, 1.0%, 0.6% and 0.1% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

For the population in Norway, the mortality table K 2005, including the minimum requirements from The Financial Supervisory Authority of Norway ("Finanstilsynet"), is used as the best mortality estimate. The requirement adjustments reduce the mortality rate with a minimum of 15% for male and 10% for female employees. The disability table, KU, has been developed by the insurance company Storebrand and aligns with the actual disability risk for Statoil in Norway.

Sensitivity analysis

The table below presents an estimate of the potential effects of changes in the key assumptions for the defined benefit plans. The following estimates are based on facts and circumstances as of 31 December 2012. 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:								
Projected benefit obligation at 31 December 2012	(5.6)	6.5	4.0	(3.6)	(1.3)	1.3	3.3	(3.0)
Service cost 2013	(0.4)	0.5	0.4	(0.4)	(0.1)	0.1	0.2	(0.2)

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 2012 and 2011. The long-term expected return on pension assets is based on a long-term risk-free interest rate adjusted for the expected long-term risk premium for the respective investment classes. A risk-free interest rate (the 10 year Norwegian Government bond has been extrapolated by use of a yield curve from another currency with long-term observable interest rates) is applied as a starting point for calculation of return on plan assets. The expected money market return is calculated by subtracting the expected term premium from bond yields. Based on historical data, equities and real estate are expected to provide a long-term return above that of the money market's.

Real estate properties owned by Statoil Pension amounted to NOK 2.1 billion and NOK 1.9 billion of total pension assets at 31 December 2012 and 2011, respectively, and are rented to Statoil companies.

Statoil Pension invests in both financial assets and real estate. The expected rate of return on real estate is estimated to be between the rate of return on equity securities and debt securities. The table below presents the portfolio weighting and expected rate of return of the finance portfolio 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*		Expected rate of return
(in %)	2012	2011			
Equity securities	38.8	29.0	40.0	(+/-5)	x + 4
Bonds	41.5	43.7	45.0	(+/-5)	x
Money market instruments	15.0	23.0	15.0	(+/-15)	x - 0.2
Real estate	3.9	4.0			
Other assets	0.8	0.3			
Total	100.0	100.0	100.0		

* The interval in brackets expresses the scope of tactical deviation by Statoil Kapitalforvaltning ASA (the asset manager).
The X in the table above represents the long-term rate of return on debt securities.

The expected company contribution related to 2013 amounts to approximately NOK 2.0 billion.

8.1.22 Provisions

(in NOK billion)	Asset retirement obligations	Other provisions	Total
Non-current portion at 31 December 2011	78.9	8.4	87.3
Long term interest bearing provisions reported as bonds, bank loans and finance lease liabilities	0.0	0.8	0.8
Current portion at 31 December 2011 reported as trade and other payables	0.9	7.9	8.8
Provisions at 31 December 2011	79.8	17.1	96.9
New or increased provisions	6.2	4.6	10.8
Unused amounts reversed	(0.9)	(2.5)	(3.4)
Amounts charged against provisions	(0.7)	(3.8)	(4.5)
Effects of change in the discount rate	5.9	0.0	5.9
Reduction due to divestments	(1.8)	(0.1)	(1.9)
Accretion expenses	3.0	0.0	3.0
Reclassification and transfer	(0.0)	(1.0)	(1.0)
Currency translation	(1.2)	(0.7)	(1.9)
Provisions at 31 December 2012	90.3	13.6	103.9
Current portion at 31 December 2012 reported as trade and other payables	1.3	7.1	8.4
Non-current portion at 31 December 2012	89.0	6.5	95.5

Expected timing of cash outflows

(in NOK billion)	Asset retirement obligations	Other provisions	Total
2013 - 2017	7.4	10.0	17.4
2018 - 2022	9.5	0.2	9.7
2023 - 2027	10.3	0.1	10.4
2028 - 2032	23.6	0.1	23.7
Thereafter	39.6	3.1	42.7
At 31 December 2012	90.4	13.5	103.9

The increase in asset retirement obligations is mainly due to decrease in the discount rate (credit-adjusted risk-free interest rate).

The timing of cash outflows related to asset retirement obligations primarily depends on when the production ceases at the various facilities.

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.

For further discussion of methods applied and estimates required, see note 2 *Significant accounting policies*.

8.1.23 Trade and other payables

(in NOK billion)	At 31 December 2012	2011
Trade payables	25.9	31.1
Non-trade payables and accrued expenses	17.1	21.6
Joint venture payables	19.8	19.8
Associated companies and other related party payables	9.4	10.9
Total financial trade and other payables	72.2	83.4
Non-financial trade and other payables	9.6	10.6
Trade and other payables	81.8	94.0

Included in Non-trade payables and accrued expenses are certain provisions that are further described in note 26 *Other commitments and contingencies*. For information regarding currency sensitivities, see note 28 *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 27 *Related parties*.

8.1.24 Bonds, bank loans, commercial papers and collateral liabilities

(in NOK billion)	At 31 December 2012	2011
Collateral liabilities	12.4	10.8
Current portion of non-current bonds, bank loans and finance lease obligations	5.7	7.2
Other including bank overdraft	0.3	1.8
Bonds, bank loans, commercial papers and collateral liabilities	18.4	19.8
Weighted interest rate (%)	1.02	1.65

The carrying amount for *Bonds, bank loans, commercial papers and collateral liabilities* at amortised cost together with accrued interest approximate fair value.

Collateral liabilities relate to cash received as security for a portion of Statoil's credit exposure.

8.1.25 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

In 2012, net rental expenses were NOK 17.6 billion (NOK 13.7 billion in 2011 and NOK 12.4 billion in 2010) of which minimum lease payments were NOK 20.0 billion (NOK 16.0 billion in 2011 and NOK 13.8 billion in 2010) and sublease payments received were NOK 2.4 billion (NOK 2.4 billion in 2011 and NOK 1.5 billion in 2010). No material contingent rent payments have been expensed in 2012, 2011 or 2010.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable operating leases at 31 December 2012.

(in NOK billion)	Operating leases					
	Rigs	Vessels	Other	Total	Sublease	Net total
2013	18.2	3.2	1.3	22.7	(3.5)	19.2
2014	16.6	2.4	1.2	20.2	(1.5)	18.7
2015	13.9	2.0	1.1	17.0	(1.3)	15.7
2016	9.9	1.7	1.0	12.6	(1.1)	11.5
2017	5.4	1.1	0.9	7.4	(0.6)	6.8
Thereafter	17.9	4.3	7.7	29.9	(2.7)	27.2
Total future minimum lease payments	81.9	14.7	13.2	109.8	(10.7)	99.1

Statoil had certain operating lease contracts for drilling rigs at 31 December 2012. The remaining significant contracts' terms range from two 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 NCS. These leases are shown gross as operating leases in the table above.

In 2010 Statoil entered into 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 2012 included five crude tankers. The contract's estimated nominal amount was approximately NOK 5.0 billion at year end 2012 and it is included in Vessels in the table above.

The category Other operating leases include future minimum lease payments of NOK 4.7 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 3.8 billion of the total is payable after 2017.

Statoil had finance lease liabilities of NOK 5.6 billion at 31 December 2012. The nominal minimum lease payments related to these finance leases amount to NOK 7.9 billion. *Property, plant and equipment* includes NOK 4.4 billion for finance leases that have been capitalised at year-end (NOK 10.2 billion in 2011), mainly within Machinery, equipment and transportation equipment including vessels and Refining and manufacturing plants.

8.1.26 Other commitments and contingencies

Contractual commitments

Statoil had contractual commitments of NOK 53.3 billion at 31 December 2012. The contractual commitments reflect the Statoil 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 2012, Statoil was committed to participate in 41 wells, with an average ownership interest of approximately 41%. Statoil's share of estimated expenditures to drill these wells amounts to NOK 9.6 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 duration 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 Statoil ownership share).

Nominal minimum other long-term commitments at 31 December 2012:

(in NOK billion)	Total
2013	14.4
2014	12.6
2015	13.0
2016	12.7
2017	12.7
Thereafter	102.1
Total	167.5

Contingencies
During 2012 the major part of the financial exposure related to gas sales contracts' price review claims, for which arbitration previously had been requested, was settled on commercial terms with no significant impact on the financial statements.

During the annual audits of Statoil's participation in Block 4, Block 15 and Block 17 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 three blocks up to and including 2012, the exposure for Statoil at year-end 2012 is estimated at USD 0.8 billion (NOK 4.5 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 2012, 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 2012 is mainly related to cost oil and profit oil volumes and has been estimated at USD 0.4 billion (NOK 2.1 billion). Statoil has provided in the 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.

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, respectively, in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its 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.

For information concerning provisions made related to claims and disputes, see note 22 *Provisions*.

8.1.27 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 2012 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet (Norwegian national insurance fund) of 3.33%). 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 96.6 billion, NOK 95.5 billion and NOK 81.4 billion in 2012, 2011 and 2010, respectively. Purchases of natural gas regarding the Tjelbergodden methanol plant from the Norwegian State stayed constant at NOK 0.4 billion in 2012, 2011 and 2010, respectively. The major part included in the line item Associated companies and other related party payables in note 23 *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 25 *Leases*.

Related party transactions with management are presented in note 7 *Remuneration*. Management remuneration for 2012 is presented in note 6 *Remuneration* in the financial statements of the parent company, Statoil ASA.

8.1.28 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 20 *Bonds, bank loans and finance lease liabilities* 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.

(in NOK billion)	Note	Loans and receivables	Available-for-sale	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
At 31 December 2012							
Assets							
Non-current financial investments	14	0.0	1.2	0.0	13.8	0.0	15.0
Non-current derivative financial instruments		0.0	0.0	33.2	0.0	0.0	33.2
Prepayments and financial receivables	14	2.5	0.0	0.0	0.0	2.4	4.9
Trade and other receivables	16	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	17	0.0	0.0	9.5	5.4	0.0	14.9
Cash and cash equivalents	18	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	Loans and receivables	Available-for-sale	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
At 31 December 2011							
Assets							
Non-current financial investments	14	0.0	2.9	0.0	12.5	0.0	15.4
Non-current derivative financial instruments		0.0	0.0	32.7	0.0	0.0	32.7
Prepayments and financial receivables	14	1.6	0.0	0.0	0.0	1.7	3.3
Trade and other receivables	16	94.7	0.0	0.0	0.0	9.1	103.8
Current derivative financial instruments		0.0	0.0	6.0	0.0	0.0	6.0
Current financial investments (restated)	17	0.0	0.0	0.1	5.1	0.0	5.2
Cash and cash equivalents (restated)	18	40.6	0.0	14.7	0.0	0.0	55.3
Total		136.9	2.9	53.5	17.6	10.8	221.7

(in NOK billion)	Note	Loans and receivables	Available-for-sale	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
At 31 December 2010							
Assets							
Non-current financial investments		0.0	3.0	0.0	12.3	0.0	15.3
Non-current derivative financial instruments		0.0	0.0	20.6	0.0	0.0	20.6
Prepayments and financial receivables		1.7	0.0	0.0	0.0	2.2	3.9
Trade and other receivables		68.4	0.0	0.0	0.0	7.5	75.9
Current derivative financial instruments		0.0	0.0	6.1	0.0	0.0	6.1
Current financial investments (restated)	17	0.0	0.0	2.0	6.2	0.0	8.2
Cash and cash equivalents (restated)	18	30.5	0.0	3.3	0.0	0.0	33.8
Total		100.6	3.0	32.0	18.5	9.7	163.8

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2012					
Liabilities					
Bonds, bank loans and finance lease liabilities	20	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	23	72.2	0.0	9.6	81.8
Bonds, bank loans, commercial papers and collateral liabilities	24	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

(in NOK billion)	Note	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2011					
Liabilities					
Bonds, bank loans and finance lease liabilities	20	110.8	0.0	0.8	111.6
Non-current derivative financial instruments		0.0	3.9	0.0	3.9
Trade and other payables	23	83.4	0.0	10.6	94.0
Bonds, bank loans, commercial papers and collateral liabilities	24	19.8	0.0	0.0	19.8
Current derivative financial instruments		0.0	3.0	0.0	3.0
Total		214.0	6.9	11.4	232.3

(in NOK billion)	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
At 31 December 2010				
Liabilities				
Bonds, bank loans and finance lease liabilities	99.8	0.0	0.0	99.8
Non-current derivative financial instruments	0.0	3.4	0.0	3.4
Trade and other payables	68.6	0.0	5.1	73.7
Bonds, bank loans, commercial papers and collateral liabilities	11.7	0.0	0.0	11.7
Current derivative financial instruments	0.0	4.2	0.0	4.2
Total	180.1	7.6	5.1	192.8

Fair value measurement of derivative financial instruments and financial investments
Statoil measures all derivative financial instruments and financial investments at fair value. Changes in the fair value of the derivative financial instruments are recognised in the Consolidated statement of income, within *Revenues* or within *Net financial items*, respectively, depending on their nature as commodity based derivative contracts or interest rate and foreign exchange rate derivative instruments.

Statoil's financial investments consist of the portfolios held by Statoil's captive insurance company (mainly bonds, listed equity securities and commercial papers) and investments in money market funds held for liquidity management purposes. Statoil also holds some other non-listed equity securities for long-term strategic purposes. These are classified as available-for-sale assets (AFS). Changes in fair value of the financial investments are recognised in the Consolidated statement of income within *Net financial items*, with the exception of the investments that are classified as AFS assets. Changes in fair value of these investments are recognised in the Consolidated statement of comprehensive income, while any impairment losses are recognised in the Consolidated statement of income within *Net financial items*.

When determining the fair value of derivative financial instruments and financial investments Statoil uses prices quoted in an active market to the extent possible. This will typically be for listed equity securities and government bonds. When such prices are not available Statoil uses inputs that are directly or indirectly observable in the market as a basis for valuation techniques such as discounted cash flow analysis or pricing models. When observable prices as a basis for the fair value measurement are unavailable, fair value is estimated based on internal assumptions. For more information about the methodology and assumption used when measuring the fair value of Statoil's derivative financial instruments and financial investment, see note 2 *Significant accounting policies*.

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 investment	Non-current derivative financial instruments-assets	Current financial investments (restated)	Current derivative financial instruments-assets	Cash equivalents (restated)	Non-current derivative financial instruments-liabilities	Current derivative financial instruments-liabilities	Net fair value
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
At 31 December 2011								
Level 1	7.9	0.0	4.5	0.0	0.0	0.0	0.0	12.4
Level 2	4.8	15.0	0.7	4.5	14.7	(3.9)	(3.0)	32.8
Level 3	2.7	17.7	0.0	1.5	0.0	0.0	0.0	21.9
Total fair value	15.4	32.7	5.2	6.0	14.7	(3.9)	(3.0)	67.1
At 31 December 2010								
Level 1	8.2	0.0	4.9	0.0	0.0	0.0	0.0	13.1
Level 2	4.4	6.8	3.3	4.7	3.3	(3.4)	(4.2)	14.9
Level 3	2.7	13.8	0.0	1.4	0.0	0.0	0.0	17.9
Total fair value	15.3	20.6	8.2	6.1	3.3	(3.4)	(4.2)	45.9

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 Statoil's 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 internal 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. The fair value 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 1.6 billion at end of 2012 and decreased by NOK 2.5 billion at end of 2011 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2012 and 2011 for all financial assets classified in the third level in the hierarchy are presented in the following table.

(in NOK billion)	Non-current financial investment	Non-current derivative financial instruments-assets	Current derivative financial instruments-assets	Total
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
For the year ended 31 December 2011				
Opening balance	2.8	13.8	1.4	18.0
Total gains and losses recognised				
- in statement of income	(0.5)	5.5	1.5	6.5
- in other comprehensive income	(0.2)	0.0	0.0	(0.2)
Purchases	0.7	0.0	0.0	0.7
Settlement	0.0	0.0	(1.4)	(1.4)
Transfer out of level 3	0.0	(1.5)	0.0	(1.5)
Foreign currency translation differences	(0.1)	(0.1)	0.0	(0.2)
Closing balance	2.7	17.7	1.5	21.9

The assets within level 3 during 2012 have had a net decrease in the fair value of NOK 2.7 billion. Of the NOK 1.8 billion recognised in the Consolidated statement of income during 2012 NOK 0.2 billion is related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements NOK 1.5 billion included in the opening balance for 2012 have been fully realised as the underlying volumes have been delivered during 2012 and the amount is presented as settled in the above table.

Substantially all gains and losses recognised in the Consolidated statement of income during 2012 are related to assets held at the end of 2012.

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 6 *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 2012 and 2011 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)	Net fair value	-40% sensitivity	40% sensitivity
At 31 December 2012			
Crude oil and refined products	12.9	(7.9)	7.9
Natural gas and electricity	6.5	1.1	(1.0)
At 31 December 2011			
Crude oil and refined products	14.0	(9.4)	9.4
Natural gas and electricity	8.7	2.9	(2.9)

Currency risk

Currency risks constitute significant financial risks for Statoil. Total exposure is managed at a portfolio level, in accordance with approved strategies and mandates, on a regular basis. For further information related to the currency risks and how Statoil manages these risks see note 6 *Financial risk management*.

The following currency risk sensitivities 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. By end of 2011 a change of 12% in main foreign exchange rates were viewed as reasonably possible changes. The estimated gains and the estimated losses following from a change in the foreign exchange rates would impact the Consolidated statement of income.

	Change in	
(in NOK billion)	USD	NOK
At 31 December 2012		
Net gains/losses (9% sensitivity)	(8.4)	7.7
Net gains/losses (-9% sensitivity)	8.4	(7.7)
At 31 December 2011		
Net gains/losses (12% sensitivity)	(10.4)	8.0
Net gains/losses (-12% sensitivity)	10.4	(8.0)

Interest rate risk

Interest rate risks constitute significant financial risks for Statoil. Total exposure is managed at a portfolio level, in accordance with approved strategies and mandates, on a regular basis. For further information related to the interest risks and how Statoil manages these risks, see note 6 *Financial risk management*.

The following interest rate risk sensitivity has been calculated by assuming a 0.7 percentage point reasonably possible changes in the interest rates by end of 2012. By end of 2011 a change of 1.5 percentage points in the interest rates were viewed as reasonably possible changes. The estimated gains following from a decline 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 2012		
Interest rate risk (0.7 percentage point sensitivity)	4.2	(4.2)
At 31 December 2011		
Interest rate risk (1.5 percentage point sensitivity)	10.2	(10.2)

8.1.29 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 NCS 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 2012 and 2011, and for the years ended 31 December 2012, 2011 and 2010.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

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	262.2	(272.5)	721.7
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	262.9	(328.7)	723.4
Total operating expenses	(480.4)	(76.8)	(230.5)	270.9	(516.8)
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

CONDENSED CONSOLIDATING STATEMENT OF INCOME

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	225.2	(276.5)	668.9
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	229.6	(361.2)	670.2
Total operating expenses	(463.3)	(79.4)	(193.0)	277.3	(458.4)
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

CONDENSED CONSOLIDATING STATEMENT OF INCOME

2010 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Revenues and other income	384.6	199.6	183.9	(239.3)	528.8
Net income equity accounted companies	37.4	(3.3)	0.8	(33.8)	1.1
Total revenues and other income	422.0	196.3	184.7	(273.1)	529.9
Total operating expenses	(385.6)	(75.2)	(171.0)	239.2	(392.6)
Net operating income	36.4	121.1	13.7	(33.9)	137.3
Net financial items	1.7	(2.4)	2.0	(1.8)	(0.5)
Income before tax	38.1	118.7	15.7	(35.7)	136.8
Income tax	1.8	(90.3)	(10.7)	0.0	(99.2)
Net income	39.9	28.4	5.0	(35.7)	37.6

CONDENSED CONSOLIDATING STATEMENT OF 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
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 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
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 STATEMENT OF COMPREHENSIVE INCOME

For the year ended 31 December 2010 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group
Net income	39.9	28.4	5.0	(35.7)	37.6
Other comprehensive income	2.2	2.1	0.9	(3.0)	2.2
Total comprehensive income	42.1	30.5	5.9	(38.7)	39.8

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	137.2	(175.5)	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	187.4	(181.5)	183.0
TOTAL ASSETS	612.0	452.2	485.1	(764.9)	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	24.1	(175.5)	(0.0)
Total current liabilities	164.3	113.3	61.6	(175.7)	163.5
Total liabilities	292.8	327.9	90.8	(247.0)	464.5
TOTAL EQUITY AND LIABILITIES	612.0	452.2	485.1	(764.9)	784.4

CONDENSED CONSOLIDATING BALANCE SHEET

At 31 December 2011 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group (restated)
ASSETS					
Property, plant, equipment and intangible assets	5.6	223.2	271.5	0.0	500.3
Equity accounted companies	352.3	113.0	7.5	(463.6)	9.2
Other non-current assets	23.9	18.6	18.5	0.0	61.0
Non-current financial receivables from subsidiaries	70.1	0.1	0.2	(70.4)	0.0
Total non-current assets	451.9	354.9	297.7	(534.0)	570.5
Current receivables from subsidiaries	18.3	34.3	84.6	(137.2)	0.0
Other current assets	70.5	27.0	49.7	(4.4)	142.8
Cash and cash equivalents	42.7	0.0	12.6	0.0	55.3
Total current assets	131.5	61.3	146.9	(141.6)	198.1
TOTAL ASSETS	583.4	416.2	444.6	(675.6)	768.6
EQUITY AND LIABILITIES					
Total equity	280.7	133.0	338.1	(466.6)	285.2
Non-current liabilities to subsidiaries	0.1	68.6	1.7	(70.4)	0.0
Other non-current liabilities	130.3	136.8	46.5	(1.3)	312.3
Total non-current liabilities	130.4	205.4	48.2	(71.7)	312.3
Other current liabilities	59.4	67.0	44.8	(0.1)	171.1
Current liabilities to subsidiaries	112.9	10.8	13.5	(137.2)	0.0
Total current liabilities	172.3	77.8	58.3	(137.3)	171.1
Total liabilities	302.7	283.2	106.5	(209.0)	483.4
TOTAL EQUITY AND LIABILITIES	583.4	416.2	444.6	(675.6)	768.6

CONDENSED CONSOLIDATING CASH FLOW STATEMENT

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 period	42.7	0.0	10.9	0.0	53.6
Cash and cash equivalents at the end of the period	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 (restated)
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 period	21.3	0.0	11.1	0.0	32.4
Cash and cash equivalents at the end of the period	42.7	0.0	10.9	0.0	53.6

For the year ended 31 December 2010 (in NOK billion)	Statoil ASA	Statoil Petroleum AS	Non-guarantor subsidiaries	Consolidation adjustments	The Statoil group (restated)
Cash flows provided by (used in) operating activities	26.0	67.5	29.9	(38.2)	85.2
Cash flows provided by (used in) investing activities	(48.8)	(31.5)	(43.0)	44.0	(79.3)
Cash flows provided by (used in) financing activities	27.8	(36.0)	13.2	(5.8)	(0.8)
Net increase (decrease) in cash and cash equivalents	5.0	(0.0)	0.1	0.0	5.1
Effect of exchange rate changes on cash and cash equivalents	0.2	0.0	0.1	0.0	0.3
Cash and cash equivalents at the beginning of the period	16.1	0.0	10.9	0.0	27.0
Cash and cash equivalents at the end of the period	21.3	0.0	11.1	0.0	32.4

8.1.30 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 events have occurred since 31 December 2012 that would result in a significant change in the estimated proved reserves or other figures reported as of that date.

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 2012, 9% of total proved reserves were related to such agreements (16% of oil and natural gas liquids (NGL) and 4% of gas). This compares with 10% and 12% of total proved reserves for 2011 and 2010, respectively. Net entitlement oil and gas production from fields with such agreements was 89 million boe during 2012 (75 million boe for 2011 and 84 million boe for 2010). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia. In 2012 Statoil recovered certain costs from previous operations in Iran. The related volumes have been included as entitlement production. The cost recovery from Iran has been completed and at 31 December 2012 Statoil has no recognised proved reserves from Iran.

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 2012 have been determined based on a 12-month average 2012 Brent blend price equivalent to USD 111.13/bbl. The slight increase in oil price from 2011, when the average Brent blend price was USD 110.96/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 2012 have been determined based on achieved gas prices during 2012 giving a volume weighted average gas price of 2.3 NOK/Sm3. The comparable volume weighted average gas price used to determine gas reserves at year-end 2011 was 2.1 NOK/Sm3. The US gas prices have decreased, thereby reducing the economic gas reserves in the USA slightly, while the gas prices in other parts of the world are higher than in 2011, reducing the gas reserves under PSAs.These changes are all included in the revision category in the tables below.

From the Norwegian continental shelf (NCS) Statoil is responsible, on behalf of the Norwegian State's direct financial interest (SDFI), for managing, transporting and selling the Norwegian State's oil and gas. 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 general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to Statoil, it is not possible to determine the total quantities to be purchased by Statoil under the owner's instruction.

Topic 932 requires the presentation of reserves and certain other supplemental oil and gas disclosures by geographical area, defined as country or continent containing 15% or more of total proved reserves. Norway contains 75% of total proved reserves at 31 December 2012 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 2009 through 2012, and the changes therein.

	Net proved oil and NGL reserves in million barrels oil equivalent						
	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Proved reserves							
At 31 December 2009	1,351	138	310	272	2,070	105	2,174
Revisions and improved recovery	100	(7)	31	(2)	123	1	124
Extensions and discoveries	46	56	25	47	174	-	174
Purchase of reserves-in-place	-	-	-	4	4	-	4
Sales of reserves-in-place	-	-	-	-	-	-	-
Production	(256)	(18)	(53)	(21)	(348)	(5)	(352)
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

Statoil's proved reserves of bitumen in Americas, representing less than 3% of our proved reserves, is included as oil in the table above.

	Net proved gas reserves in billion standard cubic feet						
	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Proved reserves							
At 31 December 2009	16,938	747	338	125	18,148	-	18,148
Revisions and improved recovery	394	(62)	(4)	4	332	-	332
Extensions and discoveries	381	-	227	340	948	-	948
Purchase of reserves-in-place	-	-	-	45	45	-	45
Sales of reserves-in-place	-	-	-	-	-	-	-
Production	(1,370)	(51)	(41)	(47)	(1,509)	-	(1,509)
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

	Net proved oil, NGL and gas reserves in million barrels oil equivalent						
	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Proved reserves							
At 31 December 2009	4,369	271	370	294	5,304	105	5,408
Revisions and improved recovery	170	(18)	30	(1)	182	1	183
Extensions and discoveries	114	56	65	108	343	-	343
Purchase of reserves-in-place	-	-	-	12	12	-	12
Sales of reserves-in-place	-	-	-	-	-	-	-
Production	(500)	(27)	(60)	(29)	(617)	(5)	(621)
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

Statoil's proved reserves of bitumen in Americas, representing less than 3% of our proved reserves, is included as oil in the table above.

	Consolidated companies					Equity accounted	Total
	Norway	Eurasia excluding Norway	Africa	Americas	Subtotal	Americas	Total
Net proved oil and NGL reserves in million barrels							
At 31 December 2009							
Developed	1,028	94	208	83	1,413	28	1,442
Undeveloped	322	44	102	189	656	76	733
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
Net proved gas reserves in billion standard cubic feet							
At 31 December 2009							
Developed	14,138	523	256	73	14,990	-	14,990
Undeveloped	2,800	224	83	51	3,158	-	3,158
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
Net proved oil, NGL and gas reserves in million barrels oil equivalent							
At 31 December 2009							
Developed	3,548	187	254	96	4,084	28	4,113
Undeveloped	821	84	116	198	1,219	76	1,295
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

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)	2012	At 31 December 2011	2010
Unproved properties	76.0	79.9	38.3
Proved properties, wells, plants and other equipment	896.7	827.5	704.3
Total capitalised cost	972.7	907.4	742.6
Accumulated depreciation, impairment and amortisation	(498.2)	(466.3)	(419.9)
Net capitalised cost	474.5	441.1	322.7

Net capitalised cost related to equity accounted investments as of 31 December 2012 was NOK 4.9 billion, NOK 5.6 billion in 2011 and NOK 5.8 billion in 2010. 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.

In addition capitalised cost related to oil and gas production activities classified as held for sale amounted to NOK 44.9 billion at 31 December 2010. At 31 December 2011 and 2012, no assets were classified as held for sale.

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 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
Year ended 31 December 2010					
Exploration expenditures	6.0	1.6	2.0	7.2	16.8
Development costs	29.3	2.5	11.3	10.4	53.5
Acquired proved properties	0.0	0.0	0.0	0.6	0.6
Acquired unproved properties	0.0	1.1	0.0	9.3	10.4
Total	35.3	5.2	13.3	27.5	81.3

Expenditures incurred in Oil and Gas Development Activities related to equity accounted investments in 2012 were NOK 0.4 billion, NOK 0.3 billion in 2011 and NOK 0.3 billion in 2010.

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 table has been changed compared to previous year's presentation, in order to align the result of operations for oil and gas producing activities with segment reporting for the two upstream reporting segments Development and Production Norway (DPN) and Development and Production International (DPI) as presented in Statoil's segment disclosure in note 4 *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 2012					
Sales	0.2	6.1	10.3	6.6	23.2
Transfers	212.6	6.8	27.3	21.9	268.6
Other revenues	7.9	1.3	0.2	1.0	10.4
Total revenues	220.7	14.2	37.8	29.5	302.2
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)	(9.6)	(15.6)
Total costs	(59.1)	(9.6)	(18.1)	(33.6)	(120.4)
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
Year ended 31 December 2011					
Sales	0.5	5.1	4.9	1.0	11.5
Transfers	203.6	6.1	23.1	15.6	248.4
Other revenues	7.9	0.4	0.0	13.8	22.1
Total revenues	212.0	11.6	28.0	30.4	282.0
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	(29.6)	(2.8)	(6.5)	(4.5)	(43.4)
Other expenses	(4.3)	(2.4)	(0.5)	(5.5)	(12.7)
Total costs	(59.4)	(9.0)	(12.0)	(17.1)	(97.5)
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

Consolidated companies

(in NOK billion)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year ended 31 December 2010					
Sales	0.0	2.7	2.6	0.7	6.0
Transfers	166.2	6.9	24.2	10.7	208.0
Other revenues	4.5	2.1	0.1	0.3	7.0
Total revenues	170.7	11.7	26.9	11.7	221.0
Exploration expenses	(5.5)	(1.5)	(2.0)	(6.8)	(15.8)
Production costs	(20.8)	(1.1)	(3.2)	(2.0)	(27.1)
Depreciation, amortisation and net impairment losses	(26.0)	(4.1)	(7.5)	(5.0)	(42.6)
Other expenses	(2.8)	(1.9)	(0.4)	(2.9)	(8.0)
Total costs	(55.1)	(8.6)	(13.1)	(16.7)	(93.5)
Results of operations before tax	115.6	3.1	13.8	(5.0)	127.5
Tax expense	(83.7)	(1.8)	(6.9)	1.0	(91.3)
Results of operations	31.9	1.3	7.0	(4.0)	36.2
Net income from equity accounted investments	0.1	0.7	0.0	0.0	0.8

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 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
At 31 December 2010					
Consolidated companies					
Future net cash inflows	1,353.4	99.3	163.6	145.0	1,761.3
Future development costs	(140.0)	(23.4)	(29.0)	(18.6)	(211.0)
Future production costs	(440.3)	(30.6)	(51.4)	(62.4)	(584.7)
Future income tax expenses	(567.5)	(6.8)	(30.3)	(17.5)	(622.1)
Future net cash flows	205.6	38.5	52.9	46.5	343.5
10 % annual discount for estimated timing of cash flows	(86.7)	(16.1)	(21.6)	(16.7)	(141.1)
Standardised measure of discounted future net cash flows	118.9	22.4	31.3	29.8	202.4
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	3.8	3.8
Total standardised measure of discounted future net cash flows including equity accounted investments	118.9	22.4	31.3	33.6	206.2

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK billion)	2012	2011	2010
Consolidated companies			
Standardised measure at beginning of year	302.1	202.4	174.1
Net change in sales and transfer prices and in production (lifting) costs related to future production	9.6	324.2	111.5
Changes in estimated future development costs	(63.7)	(51.7)	(40.1)
Sales and transfers of oil and gas produced during the period, net of production cost	(275.1)	(243.0)	(194.9)
Net change due to extensions, discoveries, and improved recovery	11.1	30.6	4.1
Net change due to purchases and sales of minerals in place	(13.4)	(1.9)	(0.4)
Net change due to revisions in quantity estimates	114.3	110.8	39.8
Previously estimated development costs incurred during the period	88.7	69.6	54.1
Accretion of discount	84.4	56.4	53.6
Net change in income taxes	(5.2)	(195.3)	0.6
Total change in the standardised measure during the year	(49.3)	99.7	28.3
Standardised measure at end of year	252.8	302.1	202.4
Equity accounted investments			
Standardised measure at end of year	1.0	2.5	3.8
Standardised measure at end of year including equity accounted investments	253.8	304.6	206.2

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. In previous years' reporting, each line item was presented on an undiscounted basis, with the total discounting effect of all line items presented in the Accretion of discount line item. This change is implemented to be more in line with general industry practice. The line item Net change in income taxes is presented on a discounted basis as before. The figures for 2011 and 2010 have been adjusted in order to be comparable with the presentation of changes in the standardised measure of value in 2012. The total standardised measure of value at the end of each year is not affected by this change.

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 sheet of Statoil ASA and subsidiaries as of 31 December 2012 and the related Consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended. 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 2012, and the results of their operations and their cash flows for the year then ended 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 has elected to change its policy for classification in the balance sheet of short-term financial investments with less than three months to maturity and its policy for presentation of changes in current financial investments in the statement of cash flows in 2012.

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 and 2010 Consolidated financial statements for the change in Statoil ASA's policy for classification in the balance sheet of short-term financial investments with less than three months to maturity and its policy for presentation of changes in current financial investments in the statement of cash flows in 2012. 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 and 2010 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 and 2010 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 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission , and our report dated 11 March 2013 expressed an unqualified opinion on the effectiveness of Statoil ASA's internal control over financial reporting.

/s/ KPMG AS

Stavanger, Norway
11 March 2013

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; Significant changes in accounting policies in the current period, and Note 8.1.3 Change in accounting policy, the consolidated balance sheets of Statoil ASA as of 31 December 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the two years in the period ended 31 December 2011 (the 2011 and 2010 financial statements before the effects of the adjustments 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 and 2010 financial statements, before the effects of the adjustments to retrospectively apply the change in accounting described in Notes 8.1.2 and 8.1.3, present fairly, in all material respects, the consolidated financial position of Statoil ASA at 31 December 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the two years in the period 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 Notes 8.1.2 and 8.1.3 and, accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have been properly applied. Those adjustments 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 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Consolidated balance sheet of Statoil ASA as of 31 December 2012 and the related Consolidated statements of income, comprehensive income, changes in equity and cash flows for the year then ended, and our report dated 11 March 2013 expressed an unqualified opinion on those Consolidated financial statements.

/s/ KPMG AS

Stavanger, Norway
11 March 2013

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
- 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
- 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 pricec, 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 activties.
- 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, sulfur, 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.
- 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 vapor 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, 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, 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: 22 March 2013

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 19 May 2011 (English translation).
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil ASA, dated February 27, 2002 (incorporated by reference to 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 3.10 "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 DeGolyer and MacNaughton.
Exhibit 15(a)(v)	Acknowledgement letter from Ernst & Young AS.

* 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
Item 1.	Identity of Directors, Senior Management and Advisers	N/A
Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	1.2; 4.1.2; 6; 6.1.1; 6.7
	B. Capitalization and Indebtedness	N/A
	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	5.1
Item 4.	Information on the Company	
	A. History and Development of the Company	3.1; 3.2; 4.1.4; 4.1.5; 4.2.3; 8.1.5
	B. Business Overview	2; 3; 4.1.1; 4.1.3
	C. Organizational Structure	3.1; 3.4; 3.10
	D. Property, Plants and Equipment	3.5 - 3.7; 3.14; 4.2.3; 8.1.12; 8.1.25
	Oil and Gas Disclosures	3.11.1; 3.11.2; 3.12; 3.12.1; 3.12.2; 3.12.3; 3.12.4; 8.1.30; Exhibit 15(a)(iv)
AItem 4A.	Unresolved Staff Comments	None
Item 5.	Operating and Financial Review and Prospects	
	A. Operating Results	3.13; 4.1; 4.2.4; 5.2.1; 8.1.28
	B. Liquidity and Capital Resources	4.2.1; 4.2.2; 4.2.5; 5.2.1; 5.2.2; 8.1.6; 8.1.18; 8.1.20; 8.1.24; 8.1.28
	C. Research and development, Patents and Licenses, etc.	3.9.2; 8.1.8
	D. Trend Information	2; 3.3; 3.5.1; 3.5.3; 3.5.4; 3.6.1; 3.6.3; 3.6.4; 3.7.1; 3.12; 3.13.3; 4.2; 5; 8.1.26
	E. Off-Balance Sheet Arrangements	4.2.5; 4.2.6; 8.1.25; 8.1.26
	F. Tabular Disclosure of Contractual Obligations	4.2.5
	G. Safe Harbor	10
Item 6.	Directors, Senior Management and Employees	
	A. Directors and Senior Management	7.6; 7.8
	B. Compensation	7.9; 8.1.21
	C. Board Practices	7.5; 7.6; 7.8
	D. Employees	3.17.1; 3.17.3
	E. Share Ownership	6.2.1; 7.8; 7.10
Item 7.	Major Shareholders and Related Party Transactions	
	A. Major Shareholders	6.8
	B. Related Party Transactions	3.15; 8.1.27
	C. Interests of Experts and Counsel	N/A
Item 8.	Financial Information	
	A. Consolidated Statements and Other Financial Information	4.1.3; 5.3; 6.1; 8
	B. Significant Changes	8.1.30
Item 9.	The Offer and Listing	
	A. Offer and Listing Details	6.4
	B. Plan of Distribution	N/A
	C. Markets	6; 6.4; 7.7
	D. Selling Shareholders	N/A
	E. Dilution	N/A
	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
	A. Share Capital	N/A
	B. Memorandum and Articles of Association	6.1; 6.8; 7.1; 7.3; 7.10; 8.1.19
	C. Material Contracts	N/A
	D. Exchange Controls	6.6
	E. Taxation	6.5
	F. Dividends and Paying Agents	N/A
	G. Statements by Experts	N/A
	H. Documents On Display	1.1
	I. Subsidiary Information	N/A
Item 11.	Quantitative and Qualitative Disclosures About Market Risk	5; 8.1.6; 8.1.28
Item 12.	Description of Securities Other than Equity Securities	
	A. Debt Securities	N/A
	B. Warrants and Rights	N/A
	C. Other Securities	N/A
	D. American Depositary Shares	6.4.2
Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	None
Item 15.	Controls and Procedures	7.12; 8.2.2
Item 16A.	Audit Committee Financial Expert	7.6.1
Item 16B.	Code of Ethics	7.2
Item 16C.	Principal Accountant Fees and Services	7.11
Item 16D.	Exemptions from the Listing Standards for Audit Committees	7.7
Item 16E.	Purchases of Equity Securities by the Issuer and Affiliated Purchases	6.2
Item 16F.	Changes in Registrant's Certifying Accountant	7.11
Item 16G.	Corporate Governance	7.7
Item 17.	Financial Statements	N/A
Item 18.	Financial Statements	8
Item 19.	Exhibits	12

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

www.statoil.com