

2011/

ANNUAL REPORT
on Form 20-F



Statoil

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Annual Report on Form 20-F

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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, 2011

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)

Torggrim 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:

<u>Title of Each Class</u>	<u>Name of Each Exchange On Which Registered</u>
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

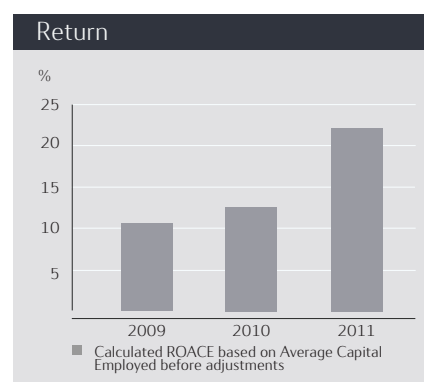
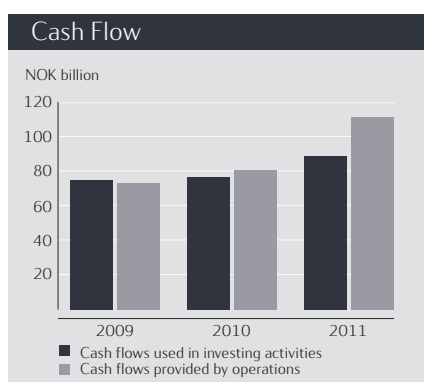
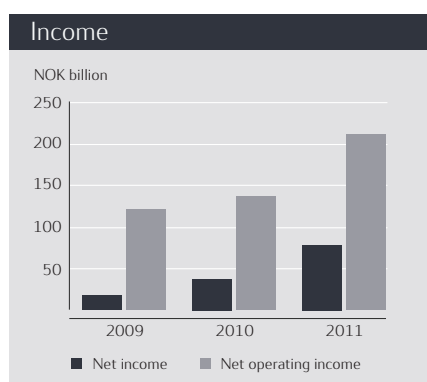
1.1 Key figures

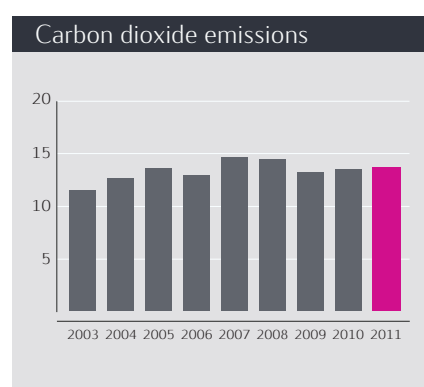
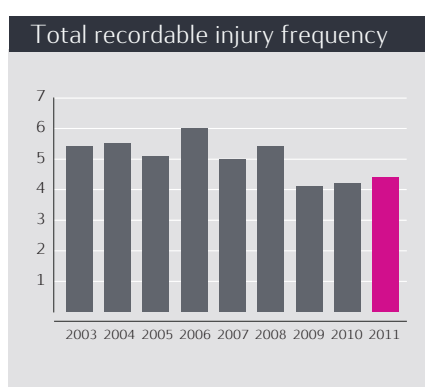
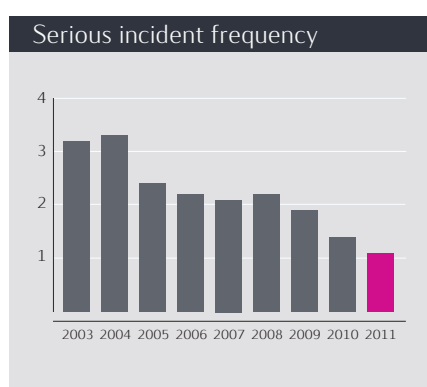
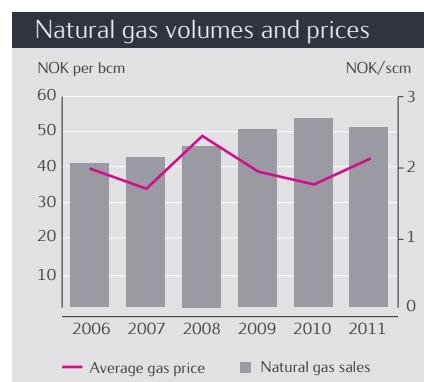
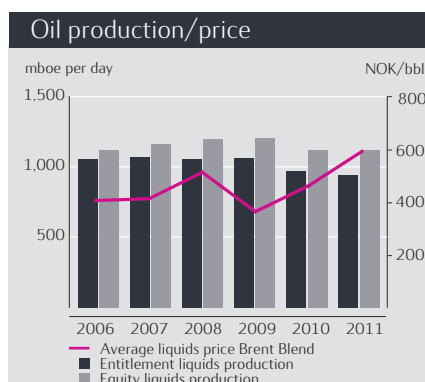
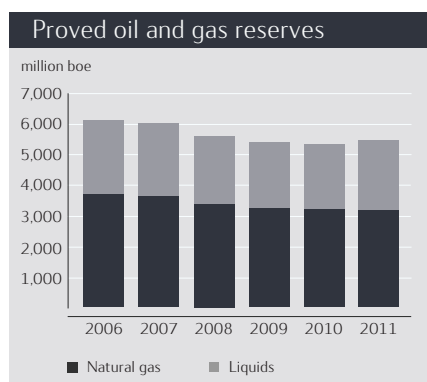
This section presents our performance in the following important areas: Income, cash flow, return, proved reserves, oil production and price, gas production and price, serious incidents, total recordable injuries and carbon dioxide emissions.

For more detailed information, see Financial Highlights. (in NOK billion, unless stated otherwise)	For the year ended 31 December ⁽¹⁾		
	2011	2010 (restated)	2009 (restated)
Net operating income	211.8	137.3	121.7
Cash flows provided by operations	111.5	80.8	73.1
Net debt to capital employed adjusted	21.1 %	25.5 %	27.6 %
Calculated ROACE based Average Capital Employed before Adjustments	22.1 %	12.6 %	10.6 %
Total equity liquids and gas production (mboe per day)	1,850	1,888	1,962
Proved oil and gas reserves (mmboe)	5,426	5,325	5,408
Production cost equity volumes (NOK/boe, last 12 months)	43.1	38.60	35.30
Proposed dividend per share NOK	6.50	6.25	6.00

⁽¹⁾ Data for the years ended 31 December 2008 and 2007 have been omitted because such financial information cannot be provided on a restated basis without unreasonable effort or expense.

The board of directors will propose the 2011 dividend for approval at the Annual General Meeting scheduled for 15 May 2012.





1.2 About the report

Statoil's Annual Report on Form 20-F for the year ended 31 December 2011 ("Annual Report on Form 20-F") is available online at www.statoil.com.

Statoil is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, Statoil files its Annual Report on Form 20-F and other related documents with the Securities and Exchange Commission, the SEC. It is also possible to read and copy documents that have been filed with the SEC at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549, USA. You may also call the SEC at 1-800-SEC-0330 for further information about the public reference rooms and their copy charges, or you may 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 <http://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.

1.3 Financial highlights

In 2011, Statoil delivered record net operating income. The value-creating Peregrino, Leismer and Gassled transactions, combined with strong oil and gas prices throughout the year, contributed to the strong financial results.

In 2011, production volumes were in line with expectations. Production start-up of new fields and ramp-up of production on existing fields combined with strong oil and gas prices enabled Statoil to deliver strong financial results and cash flows.

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).

(in NOK billion, unless stated otherwise)			
	2011	For the year ended 31 December ⁽¹⁾ 2010 (restated)	2009 (restated)
Financial information			
Total revenues and other income	670.2	529.9	465.4
Net operating income	211.8	137.3	121.7
Net income	78.4	37.6	17.7
Cash flows provided by operations	111.5	80.8	73.1
Cash flow used in investing activities	88.7	76.5	75.1
Bonds, bank loans and finance lease liabilities	111.6	99.8	96.0
Net interest-bearing liabilities before adjustments	71.0	69.5	71.8
Net interest-bearing liabilities adjusted	76.0	77.4	76.5
Total assets	768.6	643.3	563.1
Share capital	8.0	8.0	8.0
Non-controlling interest	6.2	6.9	1.8
Total equity	285.2	226.4	200.1
Net debt to capital employed ratio before adjustments	19.9 %	23.5 %	26.4 %
Net debt to capital employed ratio adjusted	21.1 %	25.5 %	27.6 %
Calculated ROACE based on Average Capital Employed before adjustments	22.1 %	12.6 %	10.6 %
Operational information			
Equity oil and gas production (mboe/day)	1,850	1,888	1,962
Proved oil and gas reserves (mmboe)	5,426	5,325	5,408
Reserve replacement ratio (three-year average)	92%	64%	64%
Production cost equity volumes (NOK/boe, last 12 months)	43.1	38.6	35.3
Share information			
Earnings per share for income attributable to equity holders of the company diluted	24.70	11.94	5.74
Share price at Oslo Stock Exchange on 31 December	153.50	138.60	144.80
Dividend paid per share NOK (2)	6.50	6.25	6.00
Dividend paid per share USD (3)	1.08	1.07	1.04
Weighted average number of ordinary shares outstanding	3,182,112,843	3,182,574,787	3,183,873,643

⁽¹⁾ Data for the years ended 31 December 2008 and 2007 have been omitted because such financial information cannot be provided on a restated basis without unreasonable effort or expense.

⁽²⁾ See Shareholder information section for a description of how dividends are determined and information on share repurchases. The board of directors will propose the 2011 dividend for approval at the Annual General Meeting scheduled for 15 May 2012.

⁽³⁾ USD figure presented using the Central Bank of Norway 2011 year-end rate for Norwegian kroner, which was USD 1.00 = 5.99 NOK. The board of directors will propose the 2011 dividend for approval at the Annual General Meeting scheduled for 15 May 2012.

1.4 A glance at 2011

Statoil delivered strong financial results and cash flows in 2011. We presented a technology-focused upstream strategy, further streamlined the portfolio, and delivered historic exploration results.

January

Effective from 1 January 2011, we have reported our business through the following reporting segments: Development and Production Norway; Development and Production International; Marketing, Processing and Renewable Energy; Fuel & Retail; Other.

We were awarded interests in 11 production licenses on the NCS, and will be operator for eight of these licenses. One of the operatorships is in the Barents Sea, one in the Norwegian Sea and six are in the North Sea.

In Angola, the national oil company Sonangol announced that Statoil had been selected for operatorship and participation in several offshore pre-salt blocks.

We announced first oil production from the Leismer Demonstration Project in Canada. Statoil's oil sands leases are located in north-east Alberta.

February

Statoil's internal investigation into the gas leakage on the Gullfaks B platform in the North Sea on 4 December 2010 was concluded and the report presented to the Petroleum Safety Authority Norway.

March

Statoil and ExxonMobil agreed to explore three Faroese offshore licenses jointly.

The Norwegian government decided to gather more facts relevant to a possible future impact assessment for Lofoten and Vesterålen. At the same time the government decided not to carry out an impact assessment for the duration of the current Norwegian parliament.

The Vega field in the North Sea and the Tyrihans subsea field in the Norwegian Sea were officially opened. The fields are expected to make important contributions to our production on the NCS.

At a ceremony in Bangkok, Statoil signed a memorandum of understanding (MoU) with PTT Exploration and Production of Thailand. Under the MoU, the companies will seek to cooperate in the areas of conventional and unconventional resources and liquefied natural gas (LNG) in a global setting.

In the Statfjord A operating plans, Statoil assumed that production shutdown may take place in 2014. Therefore we outlined a draft programme for an impact analysis of platform removal, including a description of plans for cessation and decommissioning.

Statoil received the investigation report from the Petroleum Safety Authority Norway on the Gullfaks B gas leak on 4 December 2010. Statoil published its own investigation of the incident in February.

Two new fast-track development projects were launched on the NCS, namely Gamma/Harepus and Snorre B template.

Statoil and KazMunayGas signed a heads of agreement (HoA) on the Abay block in the Kazakhstani sector of the Caspian Sea. Under the HoA, the parties will conduct an evaluation of the hydrocarbon potential of the Abay block.

April

Statoil, along with partners Eni Norway and Petoro, made a significant oil discovery on the Skrugard prospect in the Barents Sea. The discovery was one of the most important finds on the NCS of the decade, and opened a new oil province that could provide additional resource growth.

We started oil production on the Peregrino field offshore Brazil. This marked a safe and efficient start-up of Statoil's largest international operatorship to date.

A new oil find was made by Statoil immediately adjacent to the Peregrino field in the Campos Basin offshore Brazil.

May

Statoil released its inaugural 2010 Canadian Oil Sands Report Card, containing performance indicators for the Leismer Demonstration Project (LDP) and surrounding Kai Kos Dehseh leases in northern Alberta and our actions to improve environmental performance as the leases are developed.

Statoil farmed in to three offshore exploration licenses in Indonesia, significantly expanding our presence in the country.

Statoil and Petrobras signed a letter of intent to expand the cooperation between the companies in respect of exploration, and to assess how the two companies can benefit from operational synergies.

Statoil's first fast-track project - Visund South - moved ahead as planned. The seabed template commenced its journey out to the field located south of Gullfaks in the North Sea.

Statoil and Sintef, an independent research organisation in Scandinavia, signed a new and comprehensive research framework agreement.

June

Statoil decided to divest a 24.1% direct and indirect stake in the Gassled natural gas transportation infrastructure joint venture for a consideration of NOK 17.35 billion. Following this transaction, Statoil will continue to own 5.0% in the joint venture.

The plan for development and operation of the Valemon gas and condensate field in the North Sea was approved by the Norwegian parliament. Production start-up is expected in 2014.

Statoil celebrated its 10th anniversary as a listed company. We presented a technology-focused upstream strategy.

Statoil signed two agreements for the sale of the major part of Statoil's onshore wind power activities in Norway, enabling the group to focus more of its efforts on offshore wind projects.

July

Statoil and Gassnova invited suppliers to take part in a technology qualification program for full-scale carbon capture at Mongstad.

Statoil awarded the contract for construction of two new drilling rigs specifically designed for use on mature fields on the NCS.

August

The steel support structure for the Gudrun platform came into place on the North Sea field, completing the first phase of the extensive installation work carried out there.

Statoil and partners Petoro AS, Det norske oljeselskap ASA and Lundin Norway AS made a significant oil discovery on the Aldous Major South prospect (PL 265) in the North Sea. Communication between the Aldous and Avaldsnes (PL 501) oil discoveries in the North Sea was confirmed, indicating that this is one field.

September

Statoil and its partners in the Troll license decided to invest NOK 11 billion in two new compressors on Troll A. The compressors would enable the production of gas from the field at commercial volumes until 2063.

Lundin Norway AS, as operator for license PL501 located in the North Sea, announced increased estimated recoverable resources within the Avaldsnes discovery in production license PL501. Statoil confirmed a significant upside potential and that it would continue to collect and analyze data before concluding on updated estimates.

October

Statoil called off the search for a 48-year-old man reported missing on the Visund platform in the North Sea on Thursday 6 October. An extensive search of the seabed around the platform had been unsuccessful.

Statoil and Brigham Exploration Company announced that they had entered into a merger agreement for Statoil to acquire all of the outstanding shares of Brigham through an all-cash tender offer. The total equity value was approximately USD 4.4 billion. The US unconventional plays hold a substantial resource base and represent an increasingly important part of future energy supplies.

Statoil, together with partners Petoro AS, Det norske oljeselskap ASA and Lundin Norway AS, confirmed significant additional volumes in its appraisal well in the Aldous Major South discovery (PL265) in the North Sea.

November

Statoil signed an agreement to acquire Hess's 3.26% ownership in the Barents Sea Snøhvit Unit and adjacent production licenses.

Statoil, Chevron Canada and Repsol E&P Canada were named successful bidders for exploration rights on two land parcels in the Flemish Pass Basin, offshore Newfoundland and Labrador, Canada.

Statoil raised a total of USD 1.75 billion of debt in the capital markets. The transactions are expected to increase the financial flexibility of the company.

Statoil acquired a 30% participating interest from Tullow Oil in block 47 offshore Suriname.

Statoil decided to farm down three and exit five assets on the NCS for a total consideration of USD 1.625 billion. The buyer is Centrica, a UK-based energy company and an established NCS player.

Statoil and Centrica entered into a long-term gas sales agreement for the delivery of 5 billion cubic metres (bcm) per year from 2015 to 2025 to the UK market.

Statoil was awarded the operatorship and a substantial working interest in a large offshore exploration license in eastern Indonesia.

December

Statoil and Brigham Exploration Company announced that more than 92.2 percent of the outstanding shares of Brigham's common stock had been tendered to Statoil (excluding shares purchased by Statoil from Brigham). Statoil has since effected a short-form merger under Delaware law.

Statoil increased its sponsorship of the FIRST® (For Inspiration and Recognition of Science and Technology) LEGO League, involving the building of LEGO-based robots by young students. As part of the group's Heroes of Tomorrow sponsorship programme, the agreement represents the group's first global sponsorship agreement.

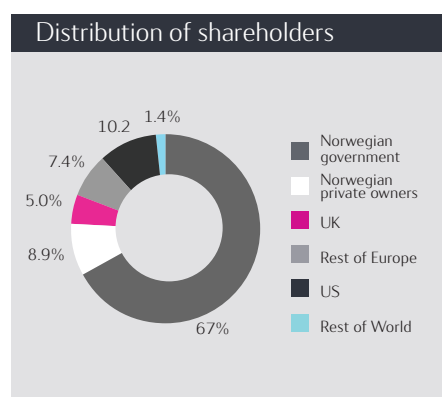
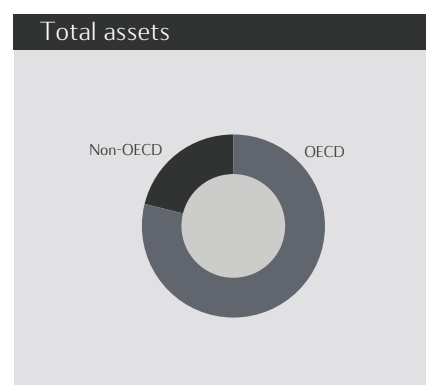
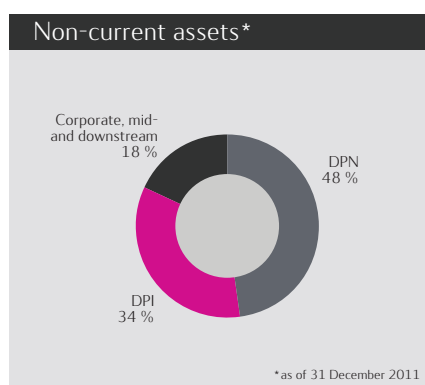
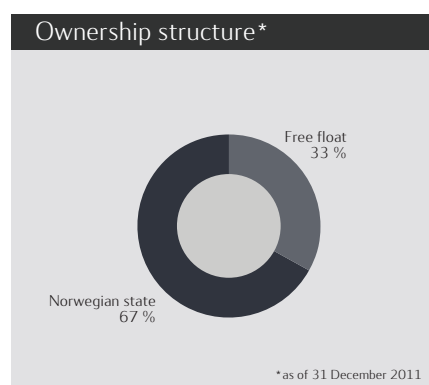
Statoil announced broad efforts to identify the direct and underlying causes of the Gullfaks C well control event on 19 May 2010. This was in response to post-incident orders from the Petroleum Safety Authority Norway.

2 Business overview and strategy

2.1 Our business

Statoil is an integrated energy company that is primarily engaged in oil and gas exploration and production activities. Statoil's headquarters are in Norway, and the company has business operations in 41 countries and territories.

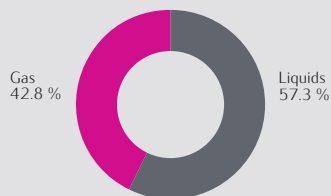
Statoil ASA is a public limited liability company organised under the laws of Norway and subject to the provisions of the Norwegian act relating to public limited liability companies (the Norwegian Public Limited Companies Act). Statoil is the leading operator on the Norwegian continental shelf (NCS). It is also expanding its international activities.



Entitlement oil and gas production outside Norway accounted for 19.6% of our total production, which averaged 1,650 mmbbl per day in 2011.

As of 31 December 2011, we had proved reserves of 2,276 mmbbl of oil and 3,150 bcm (equivalent to 17,681 tcf) of natural gas, corresponding to aggregate proved reserves of 5,426 mmbbl.

Entitlement production of liquids and gas



We have business operations in 41 countries and territories. As of 31 December 2011, there were 31,715 employees in the Statoil group. Of this total, 10,385 were employees of the Statoil Fuel & Retail group, in which we held a 54% majority ownership interest as of 31 December 2011.

We are among the world's largest net sellers of crude oil and condensate, and we are the second-largest supplier of natural gas to the European market. We also have substantial processing and refining operations. We are contributing to the development of new energy resources, have ongoing activities in the areas of offshore wind and biofuels, and are 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 water, heavy oil, harsh environments and gas value chains in order to exploit new opportunities and develop high-quality projects.

Business address

Our business address is Forusbeen 50, N-4035 Stavanger, Norway. Our telephone number is +47 51 99 00 00. Our largest locations in terms of the number of employees are in Stavanger, Bergen and Oslo, Norway.

The Statoil group, the main business areas and staff functions are presented in the following sections of this report.

The figure below provides an overview of the countries and territories in which Statoil has business operations.



2.2 Our history

Statoil was formed in 1972 by a decision of the Norwegian Storting (parliament). It was 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. On 1 October 2007, the oil and gas division of Norsk Hydro ASA was merged with Statoil, and the company was given the temporary name of StatoilHydro. On 1 November 2009, the company changed its name back to Statoil.

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.

The 1990s were characterised by substantial improvements in the production performance of our large fields. This was the result of intense technological development on the NCS. We laid the foundation for future improvements by becoming a leading company in the fields of floating production facilities and subsea development. The company grew strongly, expanded in new product markets and increased its commitment to international exploration and production.

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, which also bolstered our global competitiveness.

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 October 2010, we successfully carried out an initial public offering (IPO) 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.

2011 was a very significant year for Statoil. It started with the implementation of a new organisational model and reporting segments. Throughout the year, we delivered strong financial results and cash flows as a result of strong production in line with expectations and high gas and liquids prices. We delivered historic exploration results, particularly through the Skrugard prospect in the Barents Sea the Johan Sverdrup discovery in the North Sea and the Peregrino South discovery in Brazil. We also started oil production on the large Peregrino field off the coast of Brazil - Statoil's largest international operatorship to date.

We further streamlined our portfolio in 2011. On the divestment side, Statoil decided to divest a 24.1% direct and indirect stake in the Gassled natural gas transportation infrastructure joint venture, and entered into an agreement to farm down three and exit five assets on the NCS. On the acquisition side, Statoil and Brigham Exploration Company announced an agreement for Statoil to acquire all of the outstanding shares in Brigham. The transaction was completed in 2011.

The US unconventional plays constitute a substantial resource base and represent an increasingly important part of future energy supplies. Statoil has progressively developed industrial capabilities through early entrance into the Marcellus and Eagle Ford shale plays. Entering the Bakken and Three Forks tight oil plays and taking on operatorship is a significant new step for Statoil. We aim to position ourselves as a leading player in the fast-growing US onshore oil and gas industry.

Although petroleum-related activities on the NCS and internationally have accounted for the bulk of our business, we are increasingly participating in projects that focus on other forms of energy - such as offshore wind and carbon capture and storage (CCS) - in anticipation of the need to expand energy production, strengthen energy security and combat adverse climate change.

2.3 Our competitive position

Information about Statoil's competitive position relies on a range of sources, including analyst reports, independent market studies and our internal assessments of our market share.

The information about Statoil's competitive position in the business overview and strategy, and operational review sections is based on a number of sources - including 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.

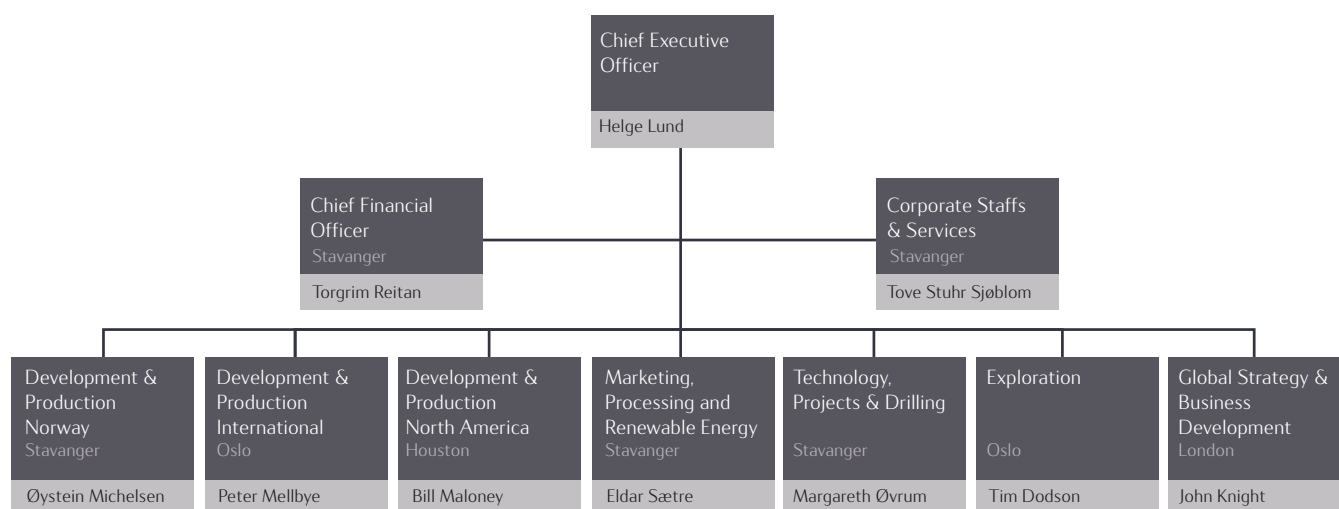
We have endeavoured to be accurate in our presentation of information based on other sources, but have not independently verified such information.

2.4 Organisational structure

A new corporate structure was implemented with effect from 1 January 2011. The changes were made in order to simplify the organisation, enhance value creation and clarify internal accountability.

The figure below illustrates the new corporate structure:

Statoil's Corporate Executive Committee and the respective business areas and staff functions



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, where 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 DPNA business areas. DPI's ambition is to build a large and profitable international production portfolio covering 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 USA and Canada. In doing this, 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, technology 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 new 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 1 January 2011, Statoil has reported its business in five 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 (SFR); and Other. See note 4 Segments, to the consolidated financial statements for additional information.

Activities relating to the Exploration business area are allocated to and presented in the respective development and production segments.

The Other reporting segment includes activities in TPD, GSB, Corporate Staffs and Services, and activities related to the CFO.

After the successful listing on the Oslo Stock Exchange in October 2010, Statoil's remaining ownership share in the listed company Statoil Fuel & Retail ASA, is 54%. SFR is fully consolidated in Statoil's financial statements, and is reported as separate reporting segment followed up by the CFO area. SFR is a leading road transportation fuel retailer that is present in eight countries in Scandinavia, and Central and Eastern Europe. SFR is also involved in the sale of stationary energy, marine fuel, aviation fuel, lubricants and chemicals. As of December 2011, SFR had a network of 2,305 service stations in its eight countries of operations. Statoil Fuel & Retail ASA also markets refined products directly to consumer and industrial markets.

2.5 Strategy

Statoil's vision is "Crossing Energy Frontiers". It guides our long-term strategy as an upstream-oriented and technology-based energy company.

At the heart of our strategy is a strong focus on operations and HSE. We operate in an industry that is becoming increasingly complex. Access to and competition for resources is becoming more challenging. The pace of change will continue to increase in the future and the importance of quality in execution will be even higher - making safe and efficient operations more important than ever.

2.5.1 Our business environment

While the current global economic situation is fragile, non-OECD economies are still growing at an impressive rate. This factor should play a large role in keeping global energy demand high in the future.

Since the 2008 financial crisis, OECD countries have struggled to stage a stable and sustained recovery. Key economies are hampered by high sovereign debt and large deficits. Households and businesses remain very cautious, and a rebalancing of public and private balance sheets in the OECD will take time. Non-OECD economies, on the other hand, have remained relatively robust, growing at about three times the pace of the OECD average.

Global oil demand climbed slightly in 2011 as growth in non-OECD markets offset the decline in the OECD markets. In spite of muted demand, prices hovered around USD 110/bbl for much of 2011, in contrast to the period 2008-2009, when demand contraction led prices to fall to below USD 40/bbl. The ramp-up in prices as demand rebounded in 2010 reflected growing concern about future capacity additions, which, along with actual supply-side shocks, continued to play a role in maintaining high prices in 2011.

In gas markets, 2011 was marked by a 9% increase in LNG imports to Asia in the wake of the Fukushima tragedy. This increase contrasted with stagnant North American and declining European demand. The recovery in gas demand following the 2008-2009 recession heralded a new paradigm in pricing as continued aggressive development of unconventional gas in North America broke the link between Henry Hub and UK National Balancing Point (NBP) and Asian LNG prices. Henry Hub was below USD 4/MMBtu for much of 2011, whereas the UK NBP price was closer to USD 10/MMBtu, and Asian LNG prices were even higher, reflecting the willingness of buyers there to pay an energy security premium.

Given OECD weakness and non-OECD robustness, Statoil expects the world economy to grow by 3.1% annually over the coming 10 years, with an OECD annual average of 2.1% and a non-OECD annual average of 5.4%. This anticipated economic development pattern means increasing economic gravitation towards the East, at the expense of the West.

Solid non-OECD growth is expected to support energy demand over the next 10 years. In the period from 2011 to 2020, internal Statoil research suggests that growth in oil demand will average 1.0% (~0.8 mbpd) annually and will - along with continued concern about upstream capacity - support oil prices close to the levels seen recently. Statoil expects non-OPEC capacity to rise by only 0.3-0.4 mbpd per year on average going forward, which means increased demand for OPEC liquids and reduced OPEC spare capacity.

Statoil's internal research suggests that gas demand in Europe and North America will increase by 1-2% per year in the period up to 2020, while Asian demand will grow at around 5% per year in the same period. Both Europe and Asia will rely more on imported LNG to meet demand, which will probably result in upward pressure on prices. This contrasts with the situation in North America, where continued development of shale gas is expected to maintain downward pressure on prices in the short to medium term.

The current global economic situation is fragile, and the actual development path could be either more subdued or more buoyant than currently anticipated. As a result, energy prices could vary considerably in the short to medium term.

Production to reserve growth remains a key challenge for international oil companies, as it has been over the last five to ten years. We believe Statoil's compound average growth rate in the last decade (2.7%) is highly competitive. Access to new resources has been made more difficult as a result of increasing competition and tighter fiscal conditions in many resource-holding countries. Corporate responses to this situation have been varying mixes of moves into unconventional assets such as shale gas, increased focus on exploration, and the rationalisation of asset portfolios to strengthen balance sheets and reposition for growth.

Going forward, the decline of legacy fields and the increasingly technically challenging nature of new field developments are expected to put upward pressure on capital and operational expenditures. Together with depressed equity markets and tightening credit, this will put a strain on the liquidity of many industry players in the years ahead and may trigger industry restructuring.

2.5.2 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 made sound strategic progress in 2011. First, a major reorganisation was implemented at the beginning of the year, then an updated strategy was presented to investors in June.

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

To succeed going forward we are focusing strategically on the following:

- Revitalising Statoil's legacy position on the NCS
- Building offshore clusters
- Developing into a leading exploration company
- Stepping up 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 Skrugard discovery in the spring of 2011 and Havis discovery in early 2012 have increased expectations of the exploration potential of the Barents Sea. Furthermore, the Aldous/Avaldsnes

discoveries have stimulated efforts to make additional new large 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 smaller discoveries, increased oil recovery (IOR) projects and the development of larger discoveries.

Current plans put the number of IOR projects at approximately 100. Future oil price expectations will extend the economic lifetime of most of the major fields, and thereby reduce the time criticality of many of the IOR projects. This will allow for greater flexibility in determining the optimal timing of these projects.

A number of larger field developments are currently in the project pipeline. They include the Luva, Dagny, Skrugard and Aldous/Avaldsnes fields, which are expected to contribute considerably to Statoil's total production over the period 2016-2020.

Of the approximately 40 smaller field development projects identified on the NCS, Statoil currently has nine projects in its fast-track development portfolio. Plans for development and operation have already been submitted for five of them (Skuld, Hyme, Stjerne, Vigdis North-East and Visund South) and two more (Visund North and Vilje South) have received licence approval. Fast-track developments are expected to contribute approximately 100,000 barrels of oil equivalent per day (boepd) by 2014.

Building offshore clusters

Statoil's international oil and gas production has increased from 100,000 to 500,000 boepd over the last decade. The company has established a presence in 41 countries and built a strong international portfolio of assets.

These countries include some of the most attractive basins in the industry - such as the USA (Gulf of Mexico [GoM] and onshore), Brazil, Angola and Azerbaijan (Caspian). Based on its efforts over the last 15-20 years, Statoil is now in a position to build at least three to five offshore clusters in select areas over the next eight to ten years.

Offshore clusters are areas that make a material contribution to total production, where Statoil is the operator 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.

The first oil from the Peregrino field in Brazil was produced in 2011. We continue to work on ramping up Peregrino production, and, in the time ahead, we will focus on further developing the Peregrino area and maturing the existing exploration portfolio.

In Angola, we are working to optimise the non-operated portfolio, and to explore the significant pre-salt acreage we were awarded in 2011 (18,400 square kilometres). This is an exciting new play with parallels to the Brazilian pre-salt acreage.

In the GoM, Statoil was one of the first oil companies to be issued a permit to resume drilling after the Macondo incident. Here, besides managing our non-operated production, we are stepping up our efforts to mature, high grade and drill the best prospects in our drilling programme, and we continue to focus on developing improved subsurface capabilities in order to increase recovery rates.

Developing into a leading exploration company

2011 has been a good year for exploration for Statoil. In fact, the company made the single biggest oil discovery worldwide in 2011 (Johan Sverdrup in the North Sea).

To replicate this success we aim to balance the strengthening of our exploration portfolio in offshore clusters (North Sea, Angola, Brazil, the Caspian and the GoM) with frontier exploration and more high-impact wells to unlock new plays (e.g. the Norwegian Sea, Barents Sea and other Arctic areas, Tanzania and Indonesia).

More specifically, we will focus on:

- A select set of basins - including frontier regions
- Drilling more significant wells
- Securing access to exploration acreage early and at scale and low cost through innovation and new ways of cooperation
- Reducing drilling costs

Stepping up our activity in unconventional resources

The Brigham acquisition in the fourth quarter of 2011 is the most recent example of our ambition to step up our position in North American unconventional resources. Building on our Alberta, Canada Kai Kos Deh Seh oil sands project - where we announced the first oil production at the Leismer Demonstration Project in January 2011 and reached one million barrels of accumulated oil production in June 2011 - our unconventional resources portfolio is now diverse, and it also includes leases in the shale gas and oil basins of Marcellus, Eagle Ford and Bakken across the USA.

Our priorities in unconventional resources include:

- Delivering on production plans
- Developing and executing a technology roadmap for unconventional resources
- Filling in our current upstream positions
- Further building for the long term through early access to land.

By 2020, we anticipate that North American production of unconventional resources will contribute in excess of 12% of Statoil's total oil and gas production.

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. Compared to our peers, the proximity of our reserves, the flexibility of our production and transportation systems and our commercial experience in gas sales and trading, puts us in a unique position in relation to the changes in the European gas market. 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, our strategic thinking is directed towards the continued promotion of gas as an important part of meeting European objectives for energy security and emission reductions. Statoil has a pan-European perspective that includes North Africa (Algeria), the Caspian and LNG options, in addition to gas from the NCS. We strongly believe that natural gas is the most cost-effective bridge to a low-carbon economy.

Beyond Europe, Statoil's 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 in terms of both 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.

The transactions signed and/or closed in 2011 (the Gassled farm-down, Brigham acquisition, Snøhvit farm-up, Valemon/Hild swap, the acquisition of Marcellus and Eagle Ford in-fill acreage and the NCS asset package sale to Centrica) further underpin our ability to redeploy capital and create value.

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

Climate change and growing demand for clean energy are 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).

Our first priority in offshore wind will be to complete the Sheringham Shoal development in the UK. Beyond Sheringham Shoal, our aim is to utilise the experience gained to develop new projects. In addition, work also continues on developing the proprietary Hywind floating offshore wind concept. Whether at Sheringham Shoal or through Hywind, our overall ambition is to play an active role in reducing costs in order to make offshore wind profitable on a stand-alone basis.

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 (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.

2.5.3 Our technology

We continually develop and deploy innovative technologies to achieve safe and efficient operations, and deliver on our strategic objectives. We have also 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 has demonstrated our ability to overcome significant technical challenges through the development and deployment of innovative technologies. At present, we are an industry leader in subsurface production and multiphase pipeline transportation.

Statoil's technology strategy is based on three main principles:

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

Prioritising business-critical technologies

Four business-critical technology aspirations need to be met in order to deliver on our strategic objectives for 2020:

- We need to be an industry leader in seismic imaging and interpretation based on proprietary technology in order to increase our discovery rates.
- We need to achieve breakthrough performance on reservoir characterisation and recovery to maximise value.
- We need a step change in well construction efficiency to drill more cost-effective wells.
- We need to develop and operate "longer, deeper and colder" subsea technologies in order to increase production and recovery. Large-scale subsea compression and complete subsea production factories are the goal by 2015 and 2020, respectively.

Strengthening our licence to operate

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 requirement 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.

3 Operational review

Statoil's operational review follows the segments resulting from the new corporate structure implemented on 1 January 2011. However, certain disclosures about oil and gas reserves are based on geographical areas, as required by the SEC.

The new corporate structure is presented in the section *Organisational structure*.

In this chapter, the operations of each reporting segment are presented. Underlying activities or business clusters are presented according to how the reporting segment organises its operations. However, the Exploration operating segment'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).

The operating segments TPD and GSB are included in the reporting segment Other.

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

For further information about disclosures concerning oil and gas reserves and certain other supplementary disclosures based upon geographical area as required by the SEC, see the sections *Operational review - Production volumes and price information* and *Operational review - Proved oil and gas reserves*.

3.1 Development and Production Norway (DPN)

3.1.1 Introduction to DPN

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

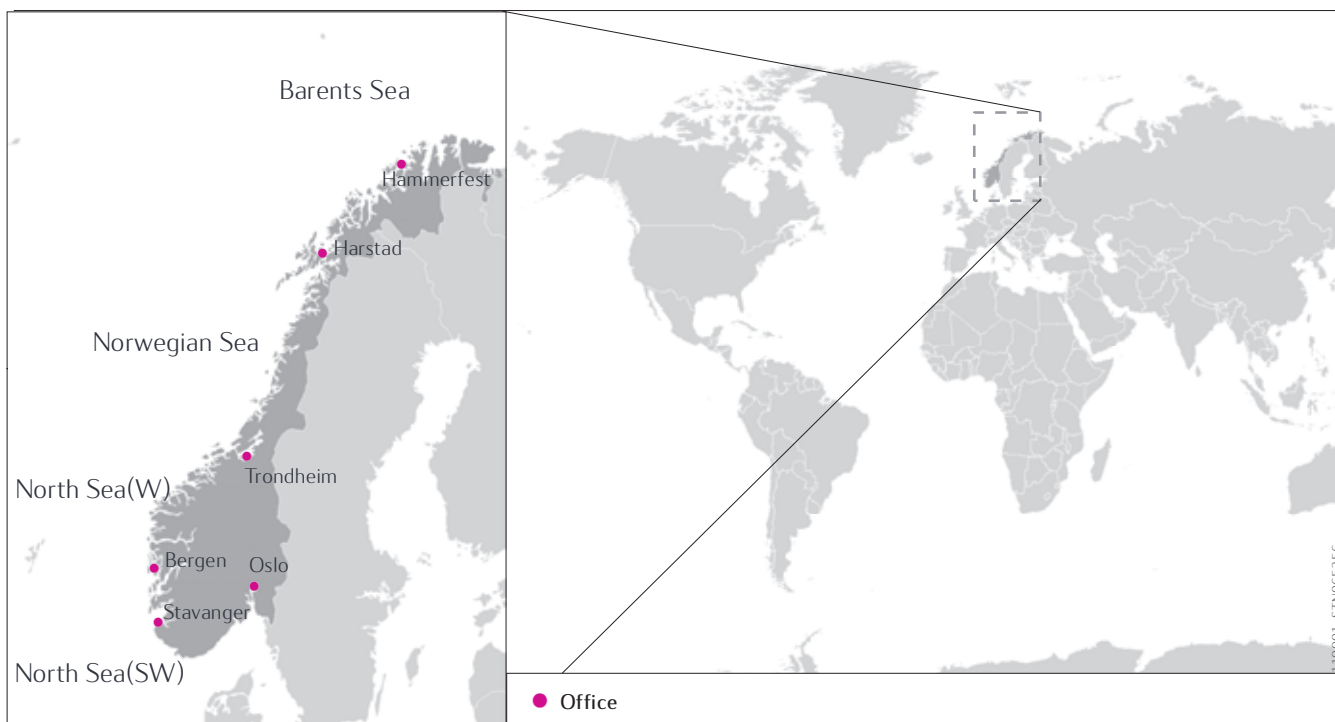


Asgard B

Development and Production Norway is the operator of 44 developed fields on the NCS. Statoil's equity and entitlement production on the NCS was 1.316 mmbbl per day in 2011, which was about 71% of Statoil's total production. Acting as operator, DPN is responsible for approximately 72% of all oil and gas production on the NCS. In 2011, our average daily production of oil and natural gas liquids (NGL) on the NCS was 693 mboe, while our average daily gas production on the NCS was 99.1 mmcm (3.5 bcf).

We have ownership interests in exploration acreage throughout the licensed parts of the NCS, both within and outside our core production areas. We participate in 227 licences on the NCS and are operator for 171 of them.

As of 31 December 2011, Statoil had a total of 1,369 mmbbl of proved oil reserves and 444 bcm (15.7 tcf) of proved natural gas reserves on the NCS.



3.1.2 DPN key events in 2011

Activity levels in Development and Production Norway were high in 2011 with several new projects sanctioned - including eight fast-track projects.

- Total entitlement liquids and gas production in 2011 amounted to 1,316 mmboe per day
- An extensive turnaround programme was completed in 2011
- Final investment decisions were made for the following projects:
 - Ormen Lange northern field development*
 - Stjerne
 - Vigdis North-East
 - Hyme
 - Åsgard subsea compression
 - Njord low pressure production
 - Snorre A drilling upgrade
 - Veslefrikk rig upgrade
 - Troll 3rd & 4th compressor
 - Skuld
 - Vilje South
 - Sleipner TKK
 - Visund Nord
 - Svalin M
 - Hild*

* Partner-operated assets

3.1.3 The NCS portfolio

Our NCS portfolio consists of licences in the North Sea, the Norwegian Sea and the Barents Sea.

We are extending production from existing fields through improved reservoir management and increased oil recovery (IOR) projects. We also operate a significant number of exploration licences.

3.1.3.1 Core production areas

Statoil's NCS portfolio consists of licences in the North Sea, the Norwegian Sea and the Barents Sea.

We have organised our production operations into four business clusters - Operations South, Operations North Sea West, Operations North Sea East and Operations North. 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.

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.

3.1.3.2 Portfolio management

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

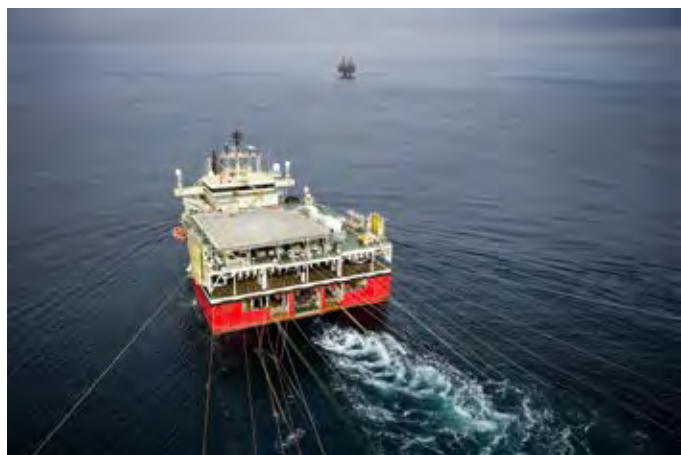
The highlights from 2011 are as follows:

- Statoil has further optimised its portfolio on the Norwegian continental shelf (NCS) by strengthening its position in growth areas through acquiring an additional interest in Snøhvit. In parallel, the company has high-graded parts of its portfolio by divesting interests and exiting certain less strategic fields.
- Statoil farmed down in three fields (Kvitebjørn, Heimdal, Valemon) and exited five (Skirne-Byggve, Fulla, Frigg-Gamma-Delta, Vale and Rind). These divestments are principally carried out through a transaction with Centrica that is expected to be closed in the 2012.

For further details regarding the above-mentioned transactions see the section *Global Strategy and Business Development (GSB) - GSB key events in 2011*.

3.1.4 Exploration on the NCS

2011 was one of the best exploration years ever for Statoil on the NCS.



The Ramford Vanguard

We made two Statoil-operated important oil discoveries during the year - the Aldous discovery (PL265) in the North Sea and the Skrugard discovery (PL532) in the Barents Sea. The number of exploration wells increased from 17 exploration wells and four exploration extensions completed in 2010 to 25 exploration wells and four exploration extensions of production wells completed in 2011. This increase is mainly due to the maturation of targets based on new knowledge gained from the extensive 2008 and 2009 drilling campaigns and new acreage awarded in the Norwegian government's 20th concession round.

The 2011 portfolio has been well-balanced and split between infrastructure-led exploration (ILX) and growth/frontier wells (higher volume potential). Eighteen of the 25 wells were wildcats drilled to test new prospects, and 15 of the wildcats were operated by us. Eleven of the 15 Statoil-operated wildcat wells were discoveries, while the three partner-operated wildcat wells were dry.

The Aldous Major South discovery in PL265 on the Utsira Height in the Sleipner area is situated 140 kilometres west of Stavanger and 35 kilometres south of the Grane field. The discovery was made in sandstone from the Jurassic age in a reservoir of very high quality. The licence was awarded to Statoil as operator in 2001. The partners are Petoro, Det norske and Lundin. Five wells have been drilled in the licence, four of which have encountered hydrocarbons. All the wells have contributed valuable information and understanding of the geological history of the area. The PL265 partnership will consider further exploration drilling to clarify the potential and optimal development solution.

The Avaldsnes discovery was made in PL501 in 2010, with Lundin as operator and Statoil and Mærsk as partners. Avaldsnes and Aldous are connected, and it is important going forward to gain a good understanding of the reservoir distribution between the two licences.

The new name for the Aldous/ Avaldsnes development is Johan Sverdrup, and Statoil is aiming for a rapid development with the ambition of starting production in 2017.

The Skrugard discovery is located about 250 kilometres off the coast from the Melkøya LNG plant in Hammerfest. The well proved to have excellent reservoir parameters, and the volume discovered is large enough for a new stand-alone development in the Barents Sea. One new wildcat well in this licence was spudded in late 2011 on the Havis prospect, with a discovery in early 2012. Following that, an appraisal well on the Skrugard discovery is being drilled after the Havis well in Q1 2012.

In addition to the Johan Sverdrup and Skrugard discoveries, we have made several commercial discoveries in the North Sea, such as Krafla, Krafla West, Opal and Rutil. These wells were drilled to add resources to our existing production installations. The Opal and Rutil discoveries are labelled fast-track candidates, which means that their development phases and production start-ups can be expedited.

We did not drill any wells in the Norwegian Sea deepwater region in 2011. The focus has been on interpreting and gaining an understanding of the 2010 well results in order to choose the right target for the next exploration well.

We were awarded 11 licences in the 21st concession round on the NCS - eight as operator and three as a partner. Four of our operatorships were awarded in the Barents Sea and four in the Norwegian Sea. All of the new licences in the Norwegian Sea are concentrated in the Luva area and fit well with the strategy for the area. In the Barents Sea, there is a strong focus on the licences surrounding the Skrugard discovery and the Hoop area, which is classified as a high-potential frontier area.

We have also been awarded interests in 11 production licences in the 2011 Awards for Pre-defined Areas (APA) on the NCS, eight of which are operatorships. In the North Sea, we will be operator in eight of the nine licences awarded, and we will participate as partner in one or two licences in the Norwegian Sea.

In June, the maritime border delimitation agreement was ratified by the Norwegian and Russian foreign ministers. The area is still immature. The Norwegian Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate have completed the first phase of seismic acquisition in the Barents Sea East and have announced that they will complete phase two for the resolved area in 2012.

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

	2011	2010	2009
North Sea			
Statoil operated exploratory	13	5	23
Statoil operated development	61	59	72
Partner operated exploratory	5	7	1
Partner operated development	12	11	17
Norwegian Sea			
Statoil operated exploratory	2	2	10
Statoil operated development	14	14	19
Partner operated exploratory	2	3	4
Partner operated development	6	6	1
Barents Sea			
Statoil operated exploratory	2	0	1
Statoil operated development	0	0	0
Partner operated exploratory	1	0	0
Partner operated development	0	0	0
Totals			
Exploratory	25	17	39
Exploration extension wells	4	4	2
Development wells	93	90	109

Potential producing areas

In addition to producing areas, Statoil operates a significant number of exploration licences. The exploration acreage is located both in undeveloped frontier areas and near infrastructure and producing fields.

Area	Square km (NCS Total)	Square km (Statoil)	Change vs 2010	Number of licenses (NCS Total)	Number of licenses (Statoil equity)	Number of licenses (Statoil Op.)	New licenses (Statoil equity)	New licenses (Statoil operated)
NCS total	126,879	48,244	(3,069)	444	227	171	27	20
North Sea	51,505	15,728	(3,788)	255	117	91	10	8
Norwegian Sea	49,709	19,893	(95)	136	79	57	10	7
Barents Sea	25,625	12,623	814	53	31	23	7	5

North Sea

In addition to the Johan Sverdrup development on the Utsira High, there are firm plans to explore other significant prospects and growth opportunities in the North Sea. Future discoveries will most likely be tied in to existing infrastructure; however, stand-alone developments will also be considered if the volumes are sufficient. The total area in which we participate has been reduced by about 4,000 square kilometres during 2011 as a result of relinquishments.

Norwegian Sea

In the Norwegian Sea, the Luva discovery in the Vøring area has passed the concept selection phase, and the project is targeted for a final investment decision and submission of a plan for development and operation within the year. The establishment of new infrastructure in this area will create a need for additional tie-in volumes, and there are plans to drill more deepwater wells in the coming years.

Barents Sea

Statoil participated in three wildcat wells and was operator for two of them. The Skrugard discovery proved to have excellent reservoir parameters and the proved reserves are sufficient to build new infrastructure in the Barents Sea and open up a new production area. There are several other promising prospects

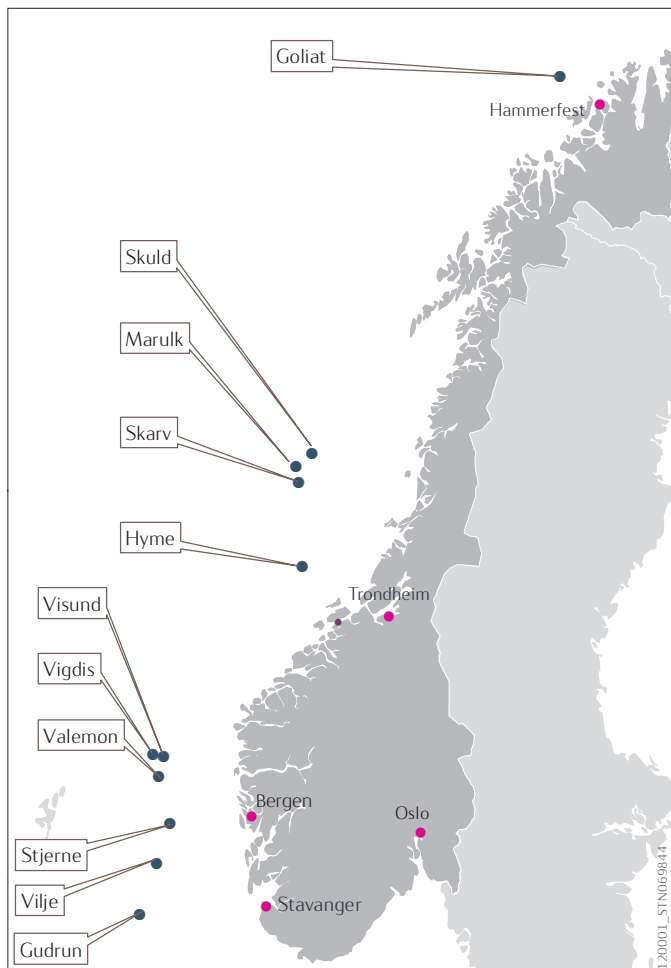
in the area, and there are firm plans to further explore this area. The newly awarded licences in the Hoop area 200 kilometres north-east of the Skrugard discovery could have the potential to create new producing areas in future.

3.1.5 Development on the NCS

The NCS is the backbone of our operations. We continue to explore and develop the NCS as an operator and partner, using the best available technology and increasingly standardised development solutions.

3.1.5.1 NCS fields under development

The following fields are currently under development on the NCS, and they include both traditional and fast-track processes.



The **Gudrun** field is located in the North Sea. 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. Gas will be further transported through the Gassled system, while oil will be transported together with Sleipner condensate by pipeline to the Gassco-operated Kårstø plant near Haugesund. The plan for development and operation (PDO) was approved by the Norwegian authorities in June 2010. Production is estimated to start in 2014. The total investments are estimated to amount to NOK 18.5 billion. On 15 December 2010, Statoil signed an agreement with Marathon Petroleum Norge to buy their 20% share of the production licences covering the Gudrun field. As a consequence of this, Statoil's share in the development is now 75%, effective from 1 April 2011.

The jacket for the processing platform has been constructed by Aker Verdal. It was successfully installed in its field location in the last week of July 2011. Conductor driving was subsequently performed, and drilling of the first production well started on 6 September, four weeks ahead of schedule. A total of seven production wells will be drilled and completed prior to production start-up.

Valemon, which is located in the North Sea, will be developed with a steel jacket platform with gas, condensate and water separation. Drilling will be performed using a jack-up rig. Rich gas will be transported via the Huldra pipeline to Heimdal for processing. Sales gas will be transported in Vesterled to St Fergus, or, alternatively, in the Statpipe pipeline to Draupner. There will be a condensate tie-in to Kvitebjørn for stabilisation and further export in pipelines to Mongstad. The PDO for the Valemon field development, submitted to the Norwegian Ministry of Petroleum and Energy (MPE) in October 2010 was approved by the Norwegian parliament on 10 June 2011. The development cost of Valemon is currently estimated to be NOK 19.8 billion, and production start-up is estimated to take place during the fourth quarter of 2014. Statoil's ownership interest in Valemon is per 31.12.2011 64.275%. In October 2011, a sales agreement was made with Centrica Resources (Norge) AS for a 13% share of Valemon, reducing Statoil's ownership interest to 53.775%. This transaction is expected to be closed in the second quarter of 2012.

Contracts for the construction of the steel jacket (Heerema Vlissingen), for transportation and installation of the jacket (Heerema Marine Contractors) and a contract for the tie-in modifications on Kvitebjørn (Bergen Group Rosenberg) have all been awarded. In addition, the contract for drilling production wells has been awarded to Seadrill Offshore AS. The drilling rig West Elara is to be used for this operation.

Visund South is located in the Tampen area of the North Sea. The field was discovered in early 2009. Statoil is the operator, with an ownership interest of 53.2%. The PDO was formally submitted to the MPE on 21 January 2011, and it was approved by the Norwegian parliament on 10 June 2011. The development cost is currently estimated to be NOK 5.6 billion. The field will be developed with a subsea template tied back to the Gullfaks C platform. The template has been constructed by FMC Technologies. It was installed on the field in June 2011. Production drilling commenced on 11 September. Production is scheduled to start in the fourth quarter of 2012.

Hyme is an oil discovery in the Halten area of the Norwegian Sea, about 15 kilometres east of the Njord field. Statoil is operator and holds a 35% ownership interest in the discovery. The PDO for the field, which was submitted to the MPE on 12 May 2011, was approved by the MPE on 28 June. The development cost is currently estimated to be NOK 4,8 billion. The selected development concept includes a subsea template that will be tied back to the Njord A platform, one multilateral production well and one water injection well. Production start-up is scheduled for the first quarter of 2013.

Stjerne is an oil discovery in the Oseberg area, located 13 kilometres south west of the Oseberg South platform. Statoil is the operator and holds a 49.3% ownership interest. The discovery was made in March 2009 and it is being developed as a one-template subsea tie-in to the Oseberg South platform, with two oil production wells and two water injection wells for pressure support. The PDO for the field was submitted to the MPE on 2 May 2011 and approved by the MPE on 16 September 2011. The development cost is currently estimated to be NOK 5.5 billion. Production start-up is scheduled for the first quarter of 2013.

Vigdis North-East is an oil discovery made in 2009 approximately seven kilometres south west of the Snorre A platform in the Tampen area of the North Sea. Statoil is the operator and holds a 41.5% ownership interest. Vigdis North-East will be developed with a subsea template tied in to the Vigdis B subsea template. The oil will be processed on the Snorre A platform. The field will be developed with three oil production wells and one well for water injection. The PDO was submitted to the MPE on 12 April 2011 and approved by the MPE on 16 September 2011. The development cost is currently estimated to be NOK 4.5 billion. Production start-up is scheduled for December 2012.

Skuld is a development project covering the Dompap and Fossekall oil discoveries north east of the Norne field in the Norwegian Sea. Dompap was discovered in 2009 and Fossekall in April 2010. Statoil is operator and holds a 63.955% ownership interest in the development. The Skuld development concept contains of one subsea template at Dompap and two subsea templates on Fossekall, and a total of six oil production wells and three water injection wells. The subsea installations will be tied back to the Norne floating production storage and offloading vessel (FPSO) through a production flowline. The PDO for the development was submitted to the MPE 26 September 2011, and sanctioned 20 January 2012. The development cost is currently estimated to be NOK 10.6 billion. Production start-up is scheduled for early 2013.

Vilje South is a southern extension of the Vilje field, located north of Heimdal in the North Sea. Vilje South is described as a possible upside in the Vilje PDO (named Mygg). The development cost is currently estimated to be NOK 1.1 billion. Statoil is the operator and holds a 28.853% ownership interest. Vilje South will be developed as a single stand-alone subsea satellite well tied back to the existing subsea facility on Vilje, with production start-up scheduled for the third quarter 2013.

Skarv is an oil and gas field located in the Norwegian Sea in which Statoil has an interest of 36.165%, with BP as operator and E.ON Ruhrgas & PGNiG as the other partners. The field is being developed with an FPSO vessel and five subsea multi-well installations. Oil will be exported by offshore loading, and gas will be exported via the Åsgard export system. The operator currently expects production to start in the second quarter of 2012. The total development cost at the investment decision was estimated to be NOK 32 billion by the operator BP.

The PDO for **Goliat** was submitted in February 2009 and approved by the Norwegian authorities in June the same year. 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, which has an interest of 65%. Statoil is the only partner, with an interest of 35%. The operator expects production start-up to occur in late 2013. The operator has estimated the development costs for the field to be NOK 31 billion.

Marulk, in which Statoil holds an interest of 50%, is a gas and condensate field located in the Norwegian Sea 25 kilometres south west of Norne. The field was discovered in 1992. The final investment decision was taken in early 2010 and proved reserves were booked in 2010. The PDO was approved by the MPE in July 2011. The field is a subsea development with two wells tied back to Norne. Rich gas will be transported through the Norne pipeline and the Åsgard Transport System for processing to sales gas at Kårstø. Condensate will be stored and offloaded commingled with the Norne crude. Production is estimated to start in the second quarter of 2012. The operator estimates the total investments to be NOK 4 billion. The operator is Eni, but Statoil is carrying out the project work.

Key figures

The table below shows some key figures as of 31 December 2011 for our major development projects.

Project	Operator	Statoil's share at 31 december 2011	Production Start	Statoil Equity Capacity (boepd)
Skarv	BP	36.17	2012	50.000
Marulk	Eni	50.00	2012	10.000
Skuld	Statoil	63.95	2013	35.000
Goliat	Eni	35.00	2013	30.000
Valemon	Statoil	64.28	2014	50.000
Gudrun	Statoil	75.00	2014	65.000

3.1.5.2 Redevelopments on the NCS

The following projects are being developed on the NCS to extend the life of existing installations, increase oil recovery and exploit new profitable opportunities.

The **Gullfaks B water injection upgrade** project includes 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 the first half of 2013.

The main purpose of the **Kvitebjørn pre-compression** project is to increase and accelerate gas and condensate recovery by facilitating low-pressure production. The project includes the installation of a turbine-driven compressor in a new module on the platform. Start-up is scheduled for December 2013.

The **Njord North-West Flank** project will enable Njord A to drill and produce from the NWF reservoir. Drilling started in October 2011 and production is scheduled to start in November 2012.

The **Troll A 3rd and 4th 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. This will enable low-pressure production from the Troll East and West gas provinces. The project was sanctioned by the licence partners in the fourth quarter 2011. The investment costs are estimated to be NOK 11 billion. The expected completion date is the fourth quarter 2015. Statoil's ownership interest in the project is 30.584%. The Troll field is located in the northern part of the North Sea.

The **Åsgard subsea compression** 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 by introducing subsea compression of the wellstream. The Åsgard subsea compression project will implement a significant amount of new subsea technology, and will be the first implementation of subsea gas compression. The PDO was submitted to the Norwegian Ministry of Petroleum and Energy (MPE) in August 2011, and approval by the authorities is expected in early 2012. The investment cost for the project is estimated to be NOK 14 billion. The expected completion date is early 2015. Statoil holds a 34.57% ownership interest in the project.

3.1.6 Fields in production on the NCS

We continued developing the NCS in 2011, and delivered strong results in a year marked with extensive turnarounds and operational challenges.

3.1.6.1 Production on the NCS

In 2011, our total entitlement oil and NGL production in Norway was 252 mmbbl, and gas production was 36.2 bcm (1,287 bcf), which represents an aggregate of 1.316 mmoep per day.

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

Business cluster	Geographical area	Statoil's equity interest in % ⁽¹⁾	Operator	On stream	Licence expiry date	Average daily production in 2011 mboe/day
Operations North						
Alve	The Norwegian Sea	85.00	Statoil	2009	2029	18.6
Kristin	The Norwegian Sea	55.30	Statoil	2005	2027 ⁽²⁾	41.0
Norne	The Norwegian Sea	39.10	Statoil	1997	2026	13.1
Urd	The Norwegian Sea	63.95	Statoil	2005	2026	3.5
Heidrun	The Norwegian Sea	38.57	Statoil	1995	2024 ⁽³⁾	28.3
Åsgard	The Norwegian Sea	34.57	Statoil	1999	2027	120.4
Mikkel	The Norwegian Sea	43.97	Statoil	2003	2020 ⁽⁴⁾	22.4
Morvin	The Norwegian Sea	64.00	Statoil	2010	2027	17.2
Njord	The Norwegian Sea	20.00	Statoil	1997	2021 ⁽⁵⁾	8.5
Tyrihans	The Norwegian Sea	58.84	Statoil	2009	2029	54.9
Snøhvit	The Barents Sea	33.53	Statoil	2007	2035	30.6
Yttergryta	The Norwegian Sea	45.75	Statoil	2009	2027	4.2
Total Operations North						362.7
Operations North Sea West						
Kvitebjørn	The North Sea	58.55	Statoil	2004	2031	100.7
Visund	The North Sea	53.20	Statoil	1999	2023	12.1
Gullfaks	The North Sea	70.00	Statoil	1986	2016	72.6
Gimle	The North Sea	65.13	Statoil	2006	2016	2.2
Grane	The North Sea	36.66	Statoil	2003	2030	50.8
Veslefrikk	The North Sea	18.00	Statoil	1989	2015	2.3
Huldra	The North Sea	19.88	Statoil	2001	2015	2.3
Glitne	The North Sea	58.90	Statoil	2001	2013	2.0
Heimdal	The North Sea	29.87	Statoil	1985	2021 ⁽⁶⁾	0.8
Brage	The North Sea	32.70	Statoil	1993	2015 ⁽⁷⁾	7.6
Vale	The North Sea	28.85	Statoil	2002	2021	0.2
Vilje	The North Sea	28.85	Statoil	2008	2021	8.8
Volve	The North Sea	59.60	Statoil	2008	2028	10.0
Total Operation North Sea West						272.5
Operations North Sea East						
Troll Phase 1 (Gas)	The North Sea	30.58	Statoil	1996	2030	132.2
Troll Phase 2 (Oil)	The North Sea	30.58	Statoil	1995	2030	38.8
Fram	The North Sea	45.00	Statoil	2003	2024	27.4
Vega Unit	The North Sea	54.00	Statoil	2010	2035 ⁽⁸⁾	16.1
Oseberg	The North Sea	49.30	Statoil	1988	2031	87.1
Tune	The North Sea	50.00	Statoil	2002	2032	4.0
Total Operation North Sea East						305.7

Business cluster	Geographical area	Statoil's equity interest in % ⁽¹⁾	Operator	On stream	Licence expiry date	Average daily production in 2011 mboe/day
Operations South (ex Partner Operated Fields)						
Statfjord Unit	The North Sea	44.34	Statoil	1979	2026	34.0
Statfjord Nord	The North Sea	21.88	Statoil	1995	2026	1.0
Statfjord Øst	The North Sea	31.69	Statoil	1994	2024 ⁽⁹⁾	2.5
Sygna	The North Sea	30.71	Statoil	2000	2024 ⁽¹⁰⁾	0.3
Snorre	The North Sea	33.32	Statoil	1992	2015 ⁽¹¹⁾	31.9
Tordis area	The North Sea	41.50	Statoil	1994	2024	9.6
Vigdis area	The North Sea	41.50	Statoil	1997	2024	16.1
Sleipner Øst	The North Sea	59.60	Statoil	1993	2028	18.2
Sleipner Vest	The North Sea	58.35	Statoil	1996	2028	85.2
Gungne	The North Sea	62.00	Statoil	1996	2028	10.9
Total Operations South (ex Partner Operated Fields)						209.7
Partner Operated Fields						
Ormen Lange	The Norwegian Sea	28.92	Shell	2007	2041	115.7
Gjøa	The North Sea	20.00	GDFSuez	2010	2028	15.4
Ekofisk area	The North Sea	7.60	ConocoPhillips	1971	2028	18.4
Ringhorne Øst	The North Sea	14.82	ExxonMobil	2006	2030	2.5
Sigyn	The North Sea	60.00	ExxonMobil	2002	2018	11.5
Enoch	The North Sea	11.78	Talisman	2007	2018	0.3
Skirne	The North Sea	10.00	Total	2004	2025	1.7
Total Partner Operated Fields						165.6
Total Operations South						375.3
Total						1,316.2

⁽¹⁾ Equity interest as of December 31, 2011.

⁽²⁾ PL134B expires in 2027 and PL199 expires in 2033

⁽³⁾ The equity interest was 12.41% in January and February 2011, 49.17% share for oil production in the period March - September 2011 and 38.56% in the period October - December 2011

⁽⁴⁾ PL092 expires in 2020 and PL121 expires in 2022

⁽⁵⁾ PL107 expires in 2021 and PL132 expires in 2023

⁽⁶⁾ 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 29.87%.

⁽⁷⁾ PL185 expires in 2015 and PL053B and PL055 both expire in 2019

⁽⁸⁾ Vega, with equity interest of 60%, and Vega Sør, with equity interest of 45%, unitised to Vega Unit

⁽⁹⁾ PL037 expires in 2026 and PL089 expires in 2024

⁽¹⁰⁾ PL037 expires in 2026 and PL089 expires in 2024

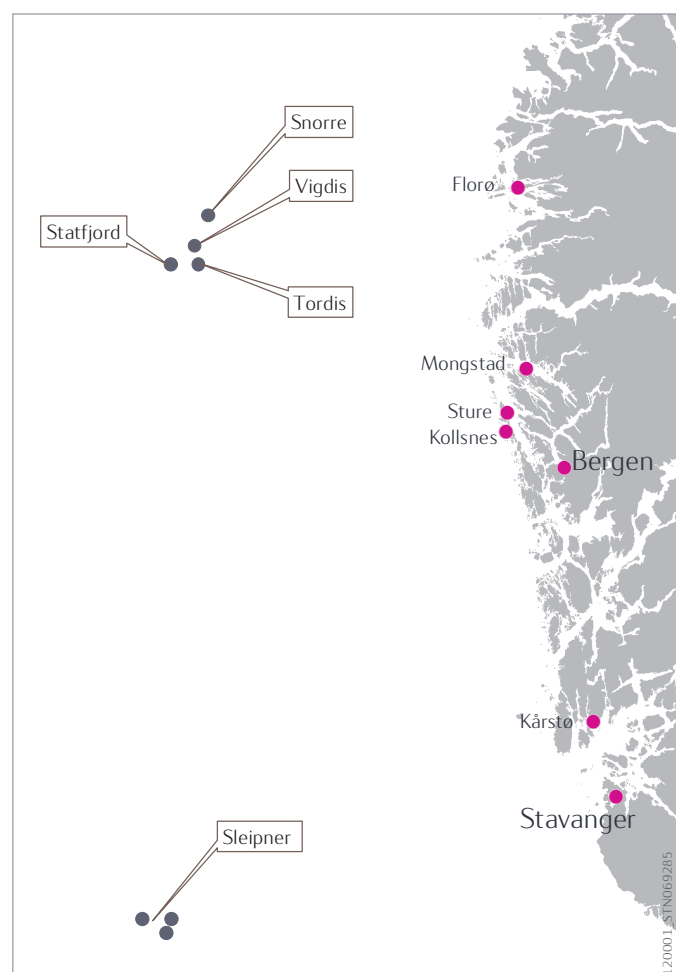
⁽¹¹⁾ PL089 expires in 2024 and PL057 expires in 2015

The following table shows our average daily entitlement production of oil, including NGL and condensates, and natural gas for each of the years ending 31 December 2011, 2010 and 2009.

Area production	2011			For the year ended December 31,			2009		
	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	214	24	363	183	24	333	175	25	332
Operations North Sea West	177	15	273	228	17	336	269	17	378
Operations North Sea East	147	25	306	138	32	337	159	26	320
Operations South (ex Partner Operated Fields)	112	16	210	119	16	220	138	20	261
Partner Operated Fields	43	19	165	36	18	147	43	18	158
Total	693	99	1,316	704	106	1,374	784	106	1,450

3.1.6.2 Operations South

Operations South includes a large part of Statoil's production activity on the NCS. The main producing fields in the Operations South area are Statfjord, Snorre, Tordis, Vigdis, Sleipner and partner-operated fields.



Statoil's share of the area's production in 2011 was 155 mbbl per day of oil, condensate and NGL, and 220 mboe per day of gas, or 375 mboe per day in total. Of this, partner-operated assets (see the section *Partner-operated fields*) accounted for 43 mbbl per day of oil, condensate and NGL, and 122 mboe per day of gas, or 165 mboe per day in total. Even after over 30 years of production from this area, we believe that there are still substantial opportunities for increased value creation.

Statoil has taken several initiatives to identify and implement measures to increase and prolong production from the Operations South area. These initiatives involve IOR, and they have resulted in a prolongation of planned production beyond the current licence period for several of the fields.

The **Snorre** field has been developed with two platforms and one subsea production system connected to one of the platforms (Snorre A). Oil and gas are exported to Statfjord for final processing, storage and loading. One satellite field, Vigdis, has been developed with a subsea tie-back to Snorre A.

The **PL 089** licence includes the Vigdis, Borg and Tordis fields. The Tordis field and the southern part of the Borg field have been developed with seven subsea satellites and two templates that are tied back to Gullfaks C, where the oil and gas are processed and stored for offshore loading and export.

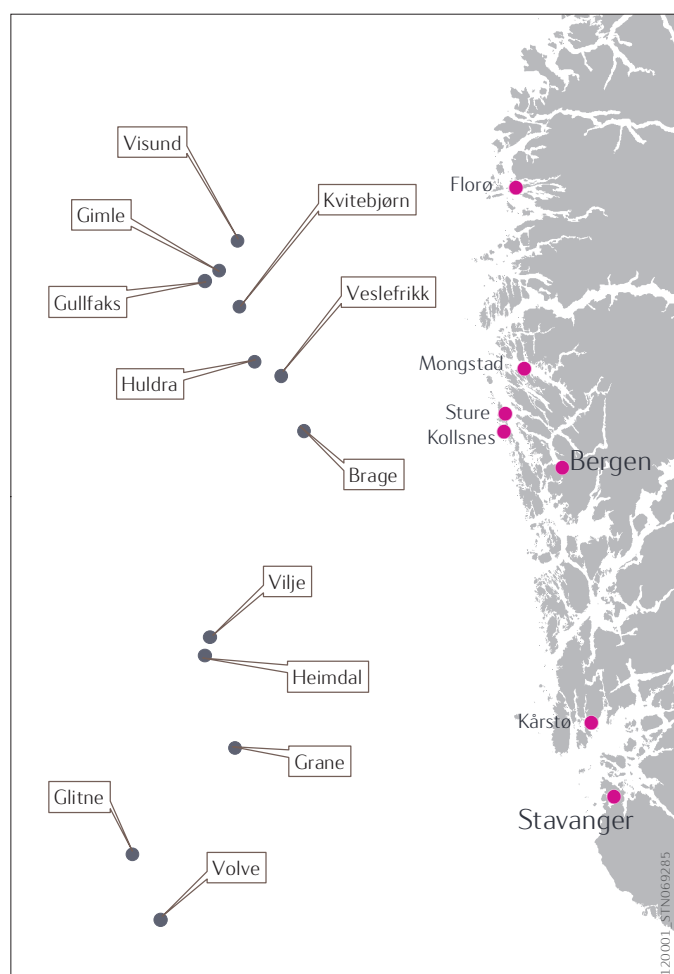
The **Vigdis** field was developed in 1997 with three subsea templates with a well stream through pipelines connected to Snorre A, where the oil is stabilised and exported to Gullfaks for storage and loading. The northern part of Borg is also produced via the Vigdis templates. The PDO for the Vigdis North-East Fast Track Project was approved by the MPE in September 2011, and production start-up is planned for the fourth quarter of 2012.

Statfjord has been developed with three fully integrated platforms supported by gravity base structures with concrete storage cells. Each platform is tied to offshore loading systems for loading oil into tankers. Associated gas is piped through the Tampen link to the UK or, alternatively, to the Kårstø gas processing plant and then on to continental Europe. Three satellite fields (Statfjord North, Statfjord East and Sygna) have been developed, each of them tied back to the Statfjord C platform. In 2005, an amended PDO was approved by the Norwegian authorities for the late-life production period for Statfjord. The Norwegian authorities granted a licence extension for the Statfjord area from 2009 to 2026. The plan is that Statfjord A production will be shut down in 2016.

Sleipner consists of the Sleipner East, Gungne and Sleipner West gas and condensate fields. Condensate from the Sleipner field is transported to the gas processing plant at Kårstø. The gas from Sleipner has a high level of carbon dioxide. It is extracted on the field and reinjected into a sand layer beneath the seabed to reduce carbon dioxide emissions to the air. We are currently exploring several prospects and discoveries in the Sleipner area that can potentially be tied in to Sleipner. Production from the Beta West structure in Sleipner West, which was discovered in 2009, was approved by the Norwegian Petroleum Directorate (NPD) in April 2011. The hydrocarbons from Gudrun will be piped to the Sleipner field. Oil and gas will be processed at Sleipner. The oil will be transported to Kårstø together with the Sleipner condensate, and the gas will be exported together with the Sleipner gas directly into the Gassled transportation system.

3.1.6.3 Operations North Sea West

Operations North Sea West includes a large part of Statoil's mature production activity on the NCS. Our main focus is on increasing and prolonging production in the area, giving priority to increased oil recovery, exploration and new field development.



The main producing fields in the Operations North Sea West area are Gullfaks, Kvitebjørn, Visund, Grane, Brage, Gimle, Veslefrikk, Huldra, Glitne, Volve and Heimdal.

The petroleum reserves are located below water depths of between 80 and 335 metres. In 2011, Statoil's share of the area's production was 177 mbbbl of oil, condensate and NGL per day and 96 mboe of gas per day, or 273 mboe per day in total.

The **Gimle** field is a Gullfaks satellite field that is operated as a separate unit. Permanent production started in May 2006, with the Gimle exploration well drilled from the Gullfaks C platform being converted into a production well. By the end of 2010, Gimle consisted of two producers and one injector, all drilled as long-reach wells from the Gullfaks C platform.

Brage is an oilfield east of Oseberg in the northern part of the North Sea. The oil is piped to Oseberg and then through the pipeline in the Oseberg Transport System to the Sture terminal. A gas pipeline is tied back to the Statpipe pipeline.

Glitne is an oilfield located about 40 kilometres north-west of Sleipner East. Glitne is the smallest field development on the NCS to use a stand-alone production system.

Grane is the first field on the NCS to produce heavy crude oil. It is Statoil's largest producing heavy oil field. The field is located to the east of the Balder field in the northern part of the North Sea. Oil from Grane is piped to the Sture terminal, where it is stored and shipped. Injection gas is imported to Grane by pipeline from the Heimdal facility. As a result, after around 25 years of oil production, Grane is producing injected gas as well.

Gullfaks 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. Five satellite fields - Gullfaks South, Rimfaks, Gullveig, Gulltopp and Skinfaks - have been developed with subsea wells that are remotely controlled from the Gullfaks A and C platforms.

Oil production from Gullfaks is gradually increasing after a well control incident at well C-06 A on Gullfaks C in May 2010. Oil production is currently significantly higher than was expected in January 2011. This is the result of active reservoir management and partially restored water injection, which is now

optimised according to strict operational criteria. Production drilling operations have also been initiated on Gullfaks satellites, and two drilling rigs are now in operation. The repair of integrity-weakened wells is ongoing according to plan.

Statoil received the Petroleum Safety Authority Norway's investigation report on the gas leak that occurred on Gullfaks B in December 2010. . Statoil published its own investigation of the incident in February 2011. The gas leak occurred in connection with the resetting of piping after maintenance of a choke valve in the wellhead area on the North Sea platform.

Heimdal is a gas field located in the northern part of the North Sea. Heimdal mainly operates as a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal, and gas from Oseberg is also transported via Heimdal. The plan for development and operation (PDO) for Valemon was submitted in October 2010. Gas from this field will be carried via the existing pipeline from Huldra to Heimdal. The PDO was approved on 9 June 2011. The lifetime of the processing facility at the Heimdal Gas Centre will thereby be extended, enabling us to maintain important processing capacity in the area.

Pre-compression plans for the **Kvitebjørn** field are expected to increase the production of gas and condensate from the field by approximately 35 million standard cubic metres (mscm) of oil equivalent, thereby increasing the recovery rate from 55% to 70%. Work on production of the compressor has already started. Offshore installation is expected to take place from 2012 until completion in early 2014.

Veslefrikk is an oilfield located north of Oseberg in the northern part of the North Sea. **Huldra** is located in the Viking Graben and developed by a normally unmanned platform that is remotely controlled from the Veslefrikk field. Oil from Veslefrikk is exported through the Oseberg Transportation System, while gas is exported to Kårstø. Veslefrikk also processes condensate from Huldra.

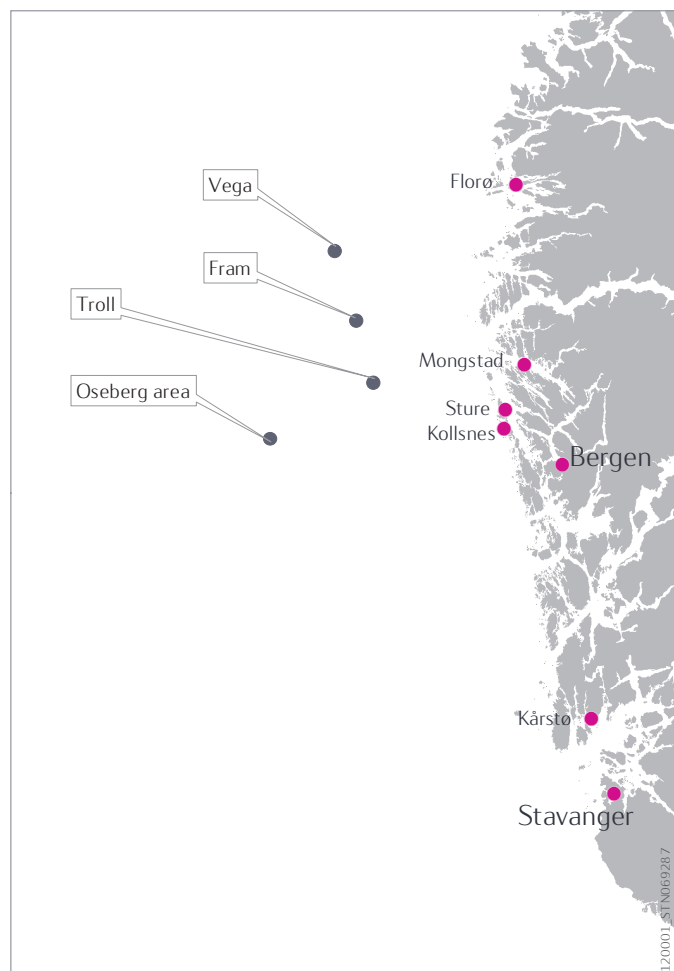
The first oil flowed from the **Vilje** field to the Alvheim FPSO on 1 August 2008. The Vilje field, which is linked to the Alvheim field, is located in the northern part of the North Sea, north of the Heimdal field.

The **Visund** oilfield is located to the east of the Snorre field in the northern part of the North Sea. The field contains oil and gas in several tilted fault blocks with separate pressure and liquid systems. The oil is piped to Gullfaks A for storage and export. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes. In April 2011, we had an incident with the Coflon risers that resulted in the risers having to be replaced and production being reduced. Three new risers were installed by November, making it possible to actively prioritise between wells in order to resume full production.

Volve is an oilfield located in the southern part of the North Sea approximately eight kilometres north of Sleipner East. The development is based on production from the *Mærsk Inspirer* jack-up rig, with *Navion Saga* being used as a storage ship for crude oil before export. Gas is piped to the Sleipner A platform for final processing and export.

3.1.6.4 Operations North Sea East

Operations North Sea East is a major gas area that also contains significant quantities of oil. The area includes the Troll, Fram, Vega, Oseberg and Tune fields.



Statoil is committed to the development of the area, and important investments have been approved in 2011. They include the investment decision to install two new compressors in Troll A for NOK 11 billion and the fast-track development of Stjerne on Oseberg for NOK 5.4 billion. Both the Oseberg and Troll areas have significant prospective potential and new IOR projects are under evaluation. In 2011, Statoil's share of the area's production was 147 mbbbl of oil, condensate and NGL per day and 159 mboe of gas per day, or 306 mboe per day in total.

The **Troll area** comprises Troll, Fram and Vega. Troll is the largest gas field on the NCS and a major oilfield.

The **Troll** field is split into three hydrocarbon-bearing regions: the Troll West Oil Province (TWOP), Troll West Gas Province (TWGP) and Troll East (TE). Oil-producing wells on TWOP and TWGP-South are tied into the Troll B platform, while oil wells on TWGP-North are tied into the Troll C platform. Most of Troll A's gas exports are produced on the giant condeep Troll A platform, which is located in the western part of the Troll East structure at a water depth of approximately 300 metres. Some gas is exported from Troll West as well. There is some limited communication between Troll East and Troll West.

Fram consists of Fram West and Fram East, both of which were awarded under the PLO90 production licence permit. Fram West is an oilfield with two subsea templates connected to Troll C. On Troll C, the gas is separated and exported via Troll A, while the rest is reinjected into the reservoir. Fram East produces from the F-East Sognefjord, C-West Sognefjord and C-West Etive reservoirs. The drainage strategy for the Sognefjord reservoirs is pressure maintenance through water injection.

The **Vega** field came on stream in December 2010. It consists of three provinces called Vega North, Vega Central and Vega South, which were previously organised under two licences and are now unitised into the Vega Unit. The production from Vega is sent to Gjøa and processed there. The Vega gas is sent to a processing facility at St Fergus (Scotland). NGL/oil

production from Vega is exported through a pipeline from Gjøa that is connected to Troll oilpipe II, which transports oil and condensate to the Mongstad refinery.

The **Oseberg area** includes the main Oseberg field, which has been developed with field centre installations and the Oseberg C production platform, and two satellite fields - Oseberg East and Oseberg South - developed with production platforms. In addition, the Tune field and Oseberg West Flank have been developed with subsea installations and tied back to the Oseberg field centre. 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 on to market.

3.1.6.5 Operations North

Our producing fields in the Operations North area are Åsgard, Mikkell, Yttergryta, Heidrun, Kristin, Tyrihans, Norne, Urd, Alve, Njord, Snøhvit and Morvin.



Our share of the area's production in 2011 was 214 mbbbl per day of oil, condensate and NGL, and 149 mboe per day of gas, or 363 mboe per day in total.

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. We plan to increase efficiency by further coordinating our operations in the area and by stemming the decline in production from the mature fields through increased seismic activity and well maintenance. In addition, we intend to expand our activities by utilising our installed production and transportation capacity before building new infrastructure.

The **Heidrun** platform is the largest concrete tension leg platform ever built. Heidrun was the first production platform in Operations North, with production start-up in 1995. Most of the oil from Heidrun 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 is a gas and condensate field in the south west section of the Operations North area. The Kristin development is the first high-temperature/high-pressure (HTHP) field developed with subsea installations. The pressure and temperature in the reservoir - 900 bar and 170 degrees Celsius, respectively - are higher than on any other developed field 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 started producing oil and gas in 2009, and the field was producing from seven wells by the end of 2011. In addition, gas is injected into two injection wells via Åsgard B. The Tyrihans development project is expected to be completed in 2012 with another two wells. All production volumes are processed on the Kristin platform.

Njord consists of two installations. Njord A is a platform with drilling facilities and a production plant for oil and gas. Njord B is a storage vessel for oil. The Njord field has produced oil since 1997, and gas export started in late 2007 via ÅTS and Kårstø.

The **Norne** field has been developed with a production and storage ship tied to subsea templates. This ship has processing facilities on deck and storage tanks for oil. Processed crude oil can be transferred over the stern to shuttle tankers. Norne is connected to gas markets in continental Europe through a link with ÅTS.

The **Urd** fields, Svale and Stær, are located ten and five kilometres north of the Norne field, respectively. The fields are produced through subsea facilities, with the well stream tied back to the Norne FPSO.

The **Alve** field, which consists of one producing well and a subsea template, was started up in March 2009. The field is produced through subsea facilities, with the well stream tied back to the Norne FPSO.

Snøhvit is the first field to be developed in the Barents Sea. Twenty wells are expected to produce natural gas from three gas reservoirs: Snøhvit, Askeladd and Albatross. By the end of 2011, Snøhvit was producing from nine wells, filling the plant capacity. All the offshore installations are subsea, which makes Snøhvit one of the first major developments without production facilities offshore. Snøhvit reinjects carbon dioxide from the liquefied natural gas (LNG) plant into a separate well/reservoir.

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. This plant is Europe's largest export factory for LNG, which is shipped to customers in Europe, the USA and Asia in tankers. The first shipment took place in late 2007. The LNG plant has also suffered from operational challenges in 2011, particularly in relation to problems with the heat exchangers, which are located in the heart of the LNG Plant (cold box). Their function is to bring down the temperature of the methane gas so that it liquidises at -164 degrees Celsius (see section *Gas Sales and Marketing - LNG* for more information). Snøhvit carried out a major turnaround in 2011 after which regularity has been high. A new 24-hour production record for Snøhvit was set on 6 August 2011, corresponding to 109% of the original design capacity of the plant.

The **Åsgard** field comprises three fields: Smørbukk, Smørbukk South and Midgard. The field 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. The subsea production installations are among the most extensive in the world, with a total of 17 seabed templates. The Åsgard B platform is the largest floating gas processing centre in the world, and Åsgard A is one of the largest floating production ships ever built. The Åsgard development links the Haltenbanken area to Norway's gas transport system in the North Sea. Gas from the field is piped through the ÅTS to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany. Oil produced at the Åsgard A vessel and condensate from the Åsgard C storage vessel are shipped from the field in shuttle tankers.

Mikkel is a gas and condensate field. Production from two seabed templates is tied to the subsea installation on Midgard for onward transportation to the Åsgard B gas processing platform.

Yttergryta produces from a single well, and the well stream is tied back to Åsgard B for processing.

Morvin started production on 1 August 2010. The field consists of two seabed templates with production from four wells. The last well was completed in spring 2011. The well stream with oil and gas is tied back to Åsgard B for processing. Morvin makes an important contribution to utilising the production capacity on Åsgard B.

3.1.6.6 Partner-operated fields

Our partner-operated fields account for a significant proportion of our oil and gas portfolio. They range from development projects to mature fields. Production is expected to start up on Skarv and Marulk in 2012.

Ormen Lange, a deepwater gas field in the Norwegian Sea, is the second-largest gas field on the NCS. Statoil has a 28.916% interest in the field. Statoil was operator for the development phase, while Norske Shell became the operator for the production phase that began at the end of 2007. Statoil continues to execute the approved, but not yet completed subsea compression pilot. The selected development is an extensive subsea development at depths ranging from 850 to 1,100 metres. 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 was the first developed field complex to come into operation on the NCS. ConocoPhillips is the operator. It consists of the Ekofisk, Eldfisk and Embla fields (in which Statoil has an interest of 7.604%), plus Tor (in which Statoil has an interest of 6.639%). Ekofisk has been upgraded with several new platforms over the years, the latest being the 2/4-M drilling platform, which was installed in 2005. In early 2010, a final investment decision was made to build a new Ekofisk accommodation and field centre platform. With 550 beds, it will be the largest in the world. 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, which consists of a new drilling and process platform. The new facilities are expected to extend the field life considerably beyond the current licence period, which ends in 2028. Redevelopment of Tor is under evaluation.

Sigyn, operated by ExxonMobil and in which Statoil has a 60% interest, is a gas and condensate field located 12 kilometres south east of the Sleipner A installation. The gas is exported from Sleipner A and the condensate is delivered to Kårstø. The development consists of three production wells on one subsea template, with two pipelines and one umbilical connecting it to the Sleipner A platform.

Statoil has a 14.82% interest in the ExxonMobil-operated **Ringhorne East** field. The unitised field started production in March 2006. Three production wells have been drilled from the Ringhorne facility. Oil is transported via Ringhorne to Balder for offshore loading. Gas is exported via Jotun into the Statpipe pipeline. A fourth and fifth production well are planned to be drilled in 2012.

Statoil has an 11.78% interest in the **Enoch** field, which is operated by Talisman. The field is a subsea development tied back to Brae A in the British sector. Production started in May 2007.

Gjøa, which is located in the North Sea, has been developed with a subsea production system and a semi-submersible production platform. Statoil was the operator during the development phase, while GDF SUEZ took over as operator from production start-up in November 2010. Statoil continues to execute the drilling and completion of the production wells into 2012. 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 Gjøa platform processes and exports volumes from both the Gjøa field and the neighbouring Vega fields. The platform is supplied with land-based electricity from Mongstad. Statoil has a 20% interest in Gjøa.

3.1.7 Decommissioning on the NCS

No Statoil-operated fields have been decommissioned during the last three years.

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). No Statoil-operated fields have been decommissioned during the last three years, however. On partner-operated fields, there has been removal activity on Frigg and Ekofisk.

In 2011, Statoil commenced execution of the Troll-Oseberg Gas injection (TOGI) decommissioning project.

For further information about decommissioning, see note 24 to the consolidated financial statements, *Asset retirement obligations, other provisions and other liabilities*.

3.2 Development and Production International (DPI)

3.2.1 Introduction to DPI

Statoil is present in several of the most important oil and gas provinces in the world, and Development and Production International (DPI) is expected to account for most of the company's future production growth.

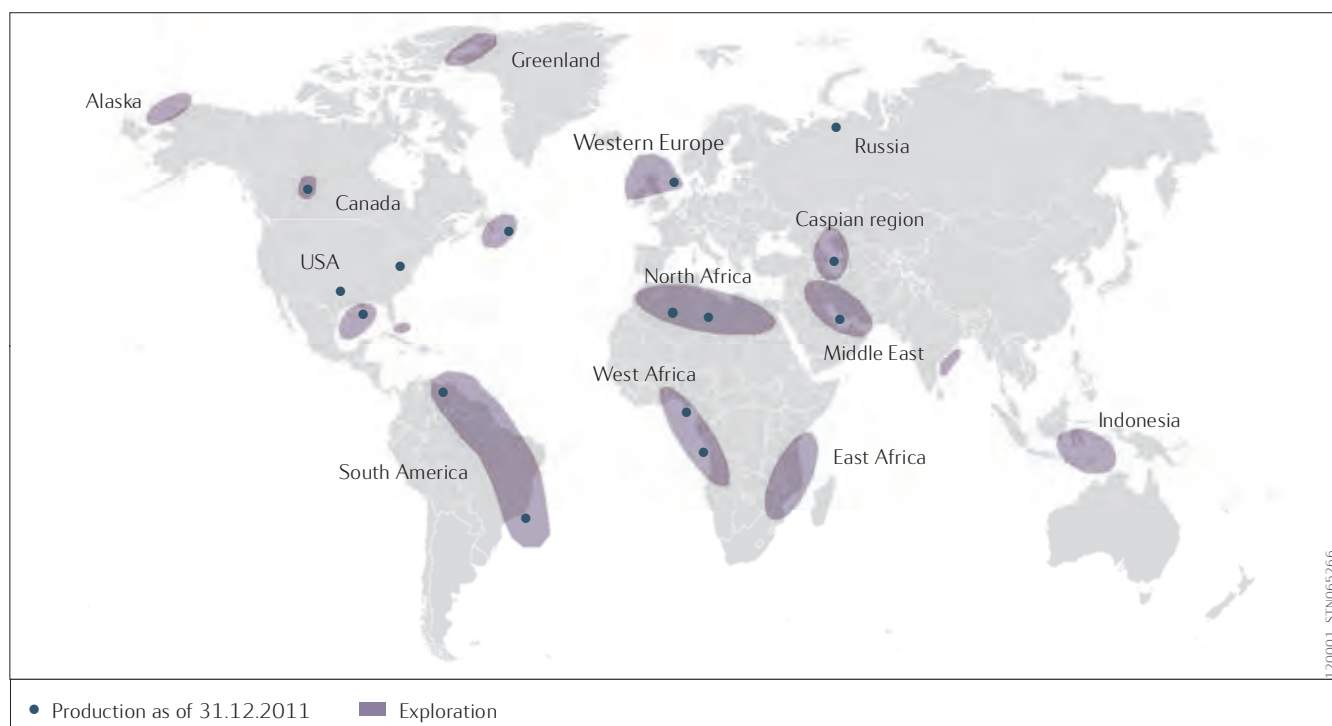
Development and Production International is responsible for the development and production of oil and gas outside the Norwegian continental shelf (NCS).

In 2011, the reporting segment was engaged in production in 12 countries: Canada, the USA, Brazil, Venezuela, Angola, Nigeria, Iran, Algeria, Libya, Azerbaijan, Russia and the UK. In 2011, DPI produced 28.9% of Statoil's total equity production of oil and gas.

Statoil has exploration licences in North America (Gulf of Mexico, Canada and Alaska), South America and sub-Saharan Africa (Brazil, Cuba, Suriname, Venezuela, Angola, Mozambique and Tanzania), Middle East and North Africa (Libya and Iran) and Europe and Asia (the Faeroes, Greenland, the UK, Azerbaijan and Indonesia).

The main sanctioned development projects in which DPI is involved are in the USA, Angola and Canada. We are well positioned for further growth through a substantial pre-sanctioned project portfolio, including a strengthened onshore US position through the acquisition of Brigham Exploration Company which was closed in December 2011.

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



3.2.2 DPI key events in 2011

International development and production continued to grow in 2011 through the start-up of several important projects.

- Equity production increased by 3.9% from 2010, to 534 mboe per day:
 - On 27 January, Statoil announced the first oil from the Leismer Demonstration Project in Canada.
 - On 9 April, the Statoil-operated Peregrino offshore field in Brazil started production.
 - On 25 June, the Hibernia Southern Extension, located off the coast of Canada, delivered its first oil.
 - On 24 August, the start-up of the Pazflor development in Angola was announced.
 - Strong ramp-up from US onshore was driven by a large number of new wells and better than expected well performance in Marcellus.
- The final investment decision was made for In Salah Southern Fields in Algeria and the Schiehallion Redevelopment in the UK.
- The acquisition of Brigham Exploration Company, which was finalised in December 2011, gives Statoil strategic exposure to US unconventional plays, which are believed to contain a substantial resource base and represent an increasingly important part of future energy supplies.
- The Peregrino South well in Brazil added significant volumes to the overall Peregrino field resource base.
- Drilling in the US Gulf of Mexico recommenced after the moratorium. Statoil is the operator there that was awarded most permits for new exploration wells by year-end (four), and it was the first operator to start a new exploration well.
- New licences in the Kwanza Basin in Angola established Statoil as a leading player in the pre-salt trend, with potential for significant new resources.
- New acreage was accessed in Canada, Indonesia and Suriname.

3.2.3 The DPI portfolio

To enhance our US growth and commitment to shale plays in 2011, we acquired Brigham Exploration Company and increased our acreage in Marcellus and Eagle Ford.

Acquisitions

In December 2011, we acquired 100% of the outstanding shares of Brigham Exploration Company. The acquisition adds production of approximately 21 mboe per day (as of December) to Statoil's production and gives us access to 1,500 square kilometres (375,000 acres) in the **Bakken** and **Three Forks** formations in the Williston Basin.

In addition to the Bakken acquisition, we continue to deepen our existing positions. In the liquids-rich **Eagle Ford**, we have increased our acreage from 67,000 to 87,974 net acres. Similarly, we have deepened our position in **Marcellus**, with continued acreage acquisitions in the northern dry gas core and south-west liquids-rich area. The total Marcellus acreage has increased from 665,000 net acres to 689,000 net acres.

Divestments and other reductions of Statoil's international portfolio

On 14 April 2011, Statoil's formation of a joint venture and sale of 40% of the Peregrino field off the coast of Brazil to the Sinochem Group was formally closed. The deal, which was first announced on 21 May 2010, has obtained all required government approvals from the Brazilian and Chinese authorities. Statoil retains 60% ownership and operatorship of the field.

With effect from January 2011, Statoil formed a joint venture with PTTEP of Thailand in its oil sands business and, as part of that transaction, sold PTTEP a 40% interest in the leases in Alberta, Canada. Statoil retains 60% ownership and operatorship of the oil sands project.

3.2.4 International exploration

Statoil supports its international growth ambitions by accessing material acreage positions early in the exploration phase. Further focus is placed on drilling an increasing number of wells with significant discovery potential.



Brigham

We have exploration licences in North America (Gulf of Mexico, Canada and Alaska), South America and sub-Saharan Africa (Brazil, Cuba, Suriname, Venezuela, Angola, Mozambique and Tanzania), Middle East and North Africa (Libya and Iran), and Europe and Asia (the Faroes, Greenland, the UK, Azerbaijan and Indonesia).

We completed 16 wells in 2011. Five were announced as discoveries: the Mukuvo and Lira discoveries in Angola, the Gavea and Peregrino South discovery in Brazil and the Logan discovery in GoM. There were five dry wells, while six wells are currently under evaluation. We plan to drill around 20 wells in 2012.

In Angola, Statoil was awarded operatorship in two new blocks and partnership in three new blocks in 2011. These blocks are all in the Angola pre-salt play.

Statoil acquired interests in six new licences in Indonesia in 2011.

Together with Chevron and Repsol, we were named successful bidders in Canada for exploration rights on two land parcels in the Flemish Pass Basin, off the coast of Newfoundland and Labrador. Statoil will be the operator of both licences, with a 50% interest.

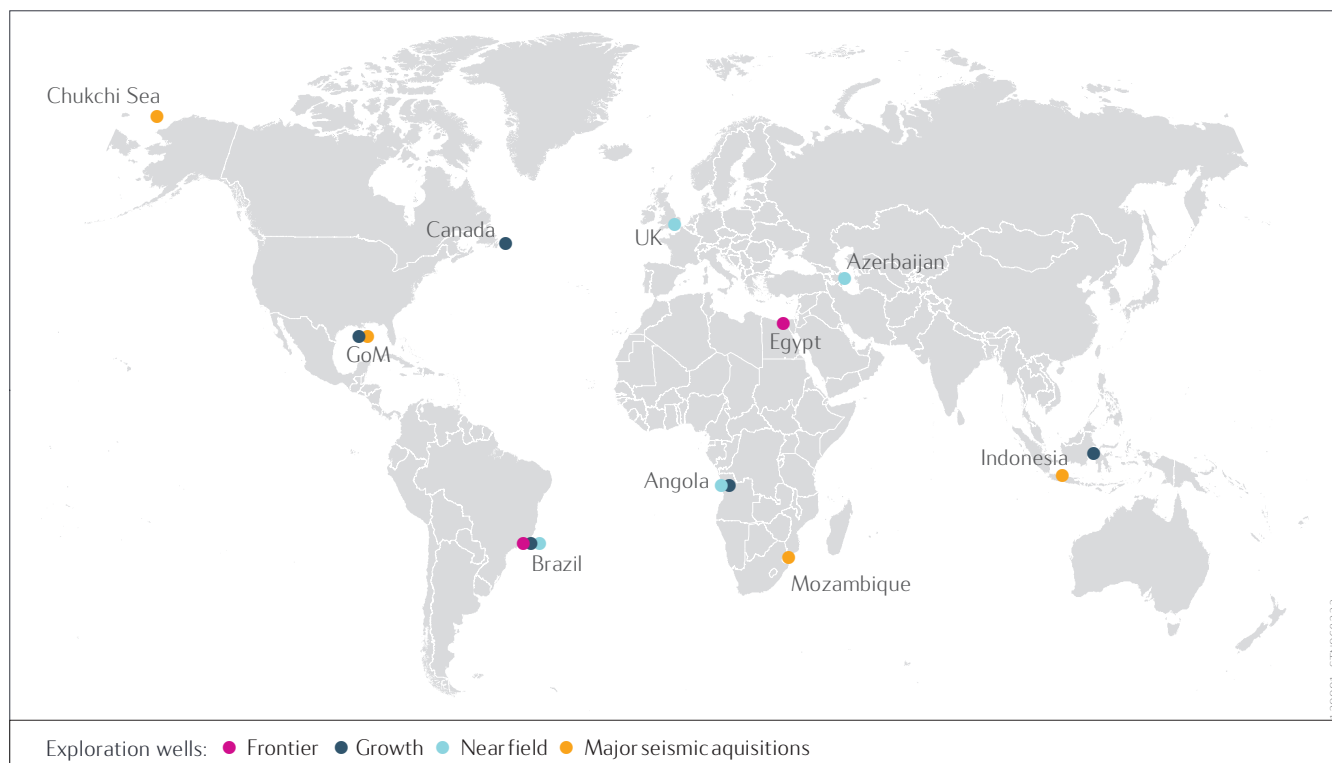
During the second half of 2011, our exploration activities in the Gulf of Mexico returned to levels similar to before the Macondo incident, which Statoil was not involved in, and two Statoil-operated wells have been completed.

We entered Suriname in 2011 through a farm-in agreement with Tullow. We have acquired a 30% working interest in block 47, with a commitment to participate in a seismic survey.

Our two licences in Egypt - El Dabaa and Ras el-Hekma - expired in 2011, after we had completed the work programme to which we were committed. We drilled one well in the El Dabaa licence, which was dry. Final closure is ongoing.

We reduced our share in three of our licences in the Faroes during 2011, selling 49% in License 006, and 50% in License 009 and License 011 to ExxonMobil. We retain a 50% interest and operatorship in each of these licenses.

Areas with drilling or significant Statoil-operated seismic activity in 2011



The areas where we had significant activity in 2011 are presented below:

Exploratory wells in Eurasia (excl. Norway), Americas and Africa

Exploratory wells 2011

	2011	2010	2009
Eurasia (Excl. Norway)	2	1	3
Statoil operated exploratory			
Partner operated exploratory	2	1	3
Americas	10	8	8
Statoil operated exploratory	7	0	0
Partner operated exploratory	3	8	8
Africa	4	9	17
Statoil operated exploratory	1		3
Partner operated exploratory	3	9	14
Totals	16	18	28

3.2.4.1 North America

Statoil has significant activities in the USA, with approximately 300 exploration leases in the Gulf of Mexico (GoM) and 66 in Alaska. We are also an operator and partner in exploration licences off the coast of Newfoundland in Canada.

3.2.4.1.1 Canada

Statoil is operator and partner in exploration licences off the coast of Newfoundland (11,138 square kilometres).



Leismer

In 2011, Statoil operated a well on the Fiddlehead prospect in the Jeanne d'Arc Basin and an appraisal well on the Mizzen discovery in the Flemish Pass Basin. The drilling operations were completed successfully and safely. Statoil successfully completed a 1,600 square-kilometre seismic 3D programme on the EL1123 licence, Cupids. We also participated in the Suncor Energy-operated Ballicatters discovery in the Jeanne d'Arc Basin.

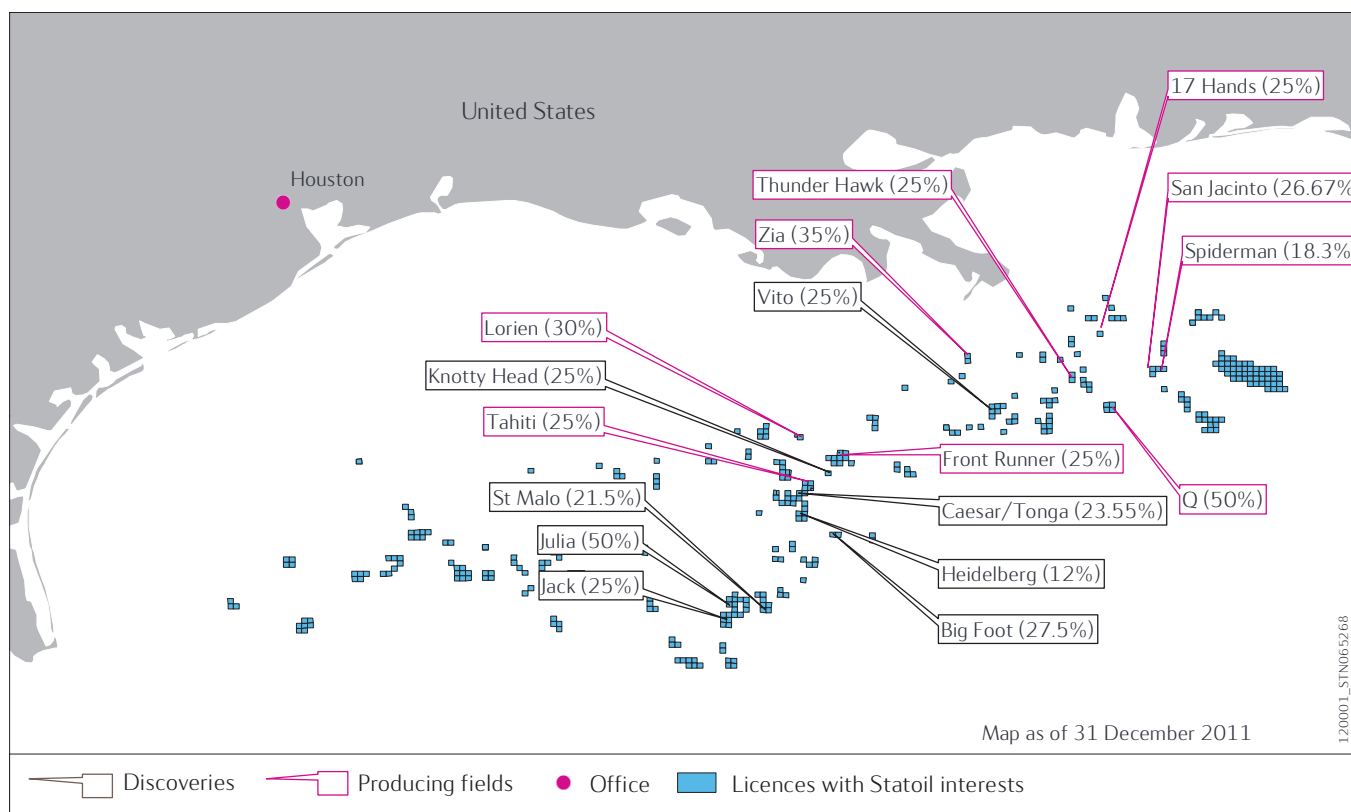
We have strengthened our offshore position in Canada and our Arctic portfolio through agreements with Chevron Canada and Repsol E&P Canada. The agreements involve three major basins off the coast of Canada: the Flemish Pass and Orphan basins off the coast of Newfoundland, and the Beaufort Sea located in Canada's high north. These new joint ventures over large land blocks in deep water represent important strategic steps for Statoil in the offshore sector in Canada, providing us with access to large potential resources and increasing the optionality of our exploration portfolio.

Statoil Canada, Chevron Canada and Repsol E&P Canada were named successful bidders for exploration rights on two land parcels in the Flemish Pass Basin, off the coasts of Newfoundland and Labrador. Statoil will be the operator of both licences with a 50% interest. Chevron Canada will have a 40% interest and Repsol E&P Canada 10%. This offers promising growth opportunities near the Statoil-operated Mizzen discovery.

Statoil intends to continue exploration activities in 2012, with one Statoil-operated well and one partner-operated well.

3.2.4.1.2 USA

Statoil has significant activities in the USA, with approximately 300 exploration leases in the Gulf of Mexico (GoM) and 66 in Alaska. Drilling activity has returned to a level similar to that before the Macondo incident.



Marcellus shale gas

US Gulf of Mexico

Statoil's exploration activities in the GoM have returned to levels similar to before the Macondo incident. Statoil operated the Cobra Paleogene well in the Alaminos Canyon and the Logan Paleogene well in Walker Ridge. The Logan well discovered hydrocarbons, and evaluations are ongoing to assess volumes and commerciality.

Statoil participated in the Deep Blue appraisal well (Noble is the operator) and is currently participating in the Kakuna exploration well (Nexen is the operator) and the Heidelberg appraisal well (Anadarko is the operator). Upon completion of the Heidelberg well in early 2012, Statoil intends to commence drilling of the Bioko Paleogene prospect, which has already been awarded a permit.

Exploration activity in the Gulf of Mexico in 2012 is expected to include three Statoil-operated exploration wells and participation in approximately four partner-operated wells.

In 2011, Statoil secured a cross assignment in the Bioko prospect with ConocoPhillips, and, together we farmed down a participation interest in the Bioko well to Shell. Statoil also succeeded in swapping interests in the Kilchurn/Innsbruck prospects with Marathon.

Alaska

Statoil opened an office in Anchorage, Alaska to support operations and activities off the Alaskan coast. Statoil carried out a successful geotechnical programme of high-resolution seismic and soil borings on our operated leases for well location planning and permitting activities. There was extensive stakeholder engagement with local communities and there were no safety or environmental incidents. Statoil continued to participate in gathering extensive baseline science data in the Chukchi Sea and signed an agreement with the National Oceanic and Atmospheric Administration (NOAA) for environmental cooperation in the Arctic.

Shale

Activity related to US onshore shale is presented below in the *International fields - North America* section.

3.2.4.2 South America and sub-Saharan Africa

We have exploration licences in Brazil, Cuba, Suriname, Venezuela, Angola, Mozambique and Tanzania.

3.2.4.2.1 Brazil

Statoil has interests in seven exploration licences in four different basins off the coast of Brazil, and it is the operator for four of the licences.

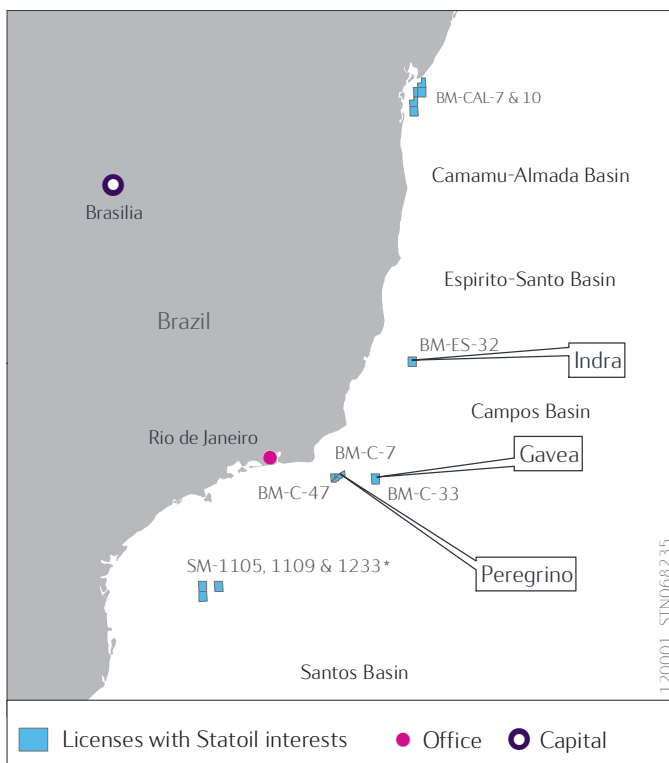


Peregrino

In 2011, we completed two Statoil-operated wells in the Campos Basin, plus three sidetracks in BM-C-47. The second well and third sidetrack were drilled in BM-C-7. All wells and sidetracks proved oil and added significant reserves to the greater Peregrino area.

We participated in the Gavea and Pão de Açúcar exploration wells in BM-C-33, which were both discoveries. Pão de Açúcar was announced in February 2012 as a significant discovery, and its development potential together with Gavea is under evaluation by the partnership. BM-C-33 is located in the Campos Basin.

In the Camamu-Almada basin, located outside Salvador, we farmed down 10% of the Petrobras-operated licence BM-CAL-7 and 15% of the Statoil-operated BM-CAL-10 to Gran Tierra. During 2011, we drilled one well in BM-CAL-10, which was dry.



Statoil also participated in one licence in the Espirito Santo basin, BM-ES-32, where the Indra discovery is located. BM-ES-29 was relinquished in 2011 after we had completed the committed work programme. The interests in three blocks that we won in the eighth round in the Santos Basin are pending award.

In 2012, Statoil expects to operate one appraisal well and take part in at least two non-operated exploration wells.

3.2.4.2.2 Angola

Statoil holds interests in blocks 4/05, 15, 15/06, 17, 22, 25, 31, 38, 39 and 40 in Angola.



Gimboa

In December 2011, Statoil was awarded licences for the operatorship of and participation in several pre-salt blocks off the coast of Angola. Statoil was awarded the following blocks as operator:

- Block 38, 6,298 square kilometres, with a 55% share (partners are Sonangol P&P and China Sonangol)
- Block 39, 7,800 square kilometres, with a 55% share (partners are Sonangol P&P and Total)

Statoil was awarded the following blocks as partner:

- Block 22, 5,180 square kilometres, with a 20% share (Repsol is operator, Sonangol P&P is partner)
- Block 25, 4,825 square kilometres, with a 20% share (Total is operator, Sonangol P&P and BP is partner)
- Block 40, 7,588 square kilometres, with a 20% share (Total is operator, Sonangol P&P is partner)

We are engaged in extensive exploration activity in Angola. A number of wells were drilled in 2011, and more are expected to be drilled in and after 2012. We have interests varying from 5% to 50% in four blocks.

In Block 4/05, which is operated by Sonangol and assisted by Statoil, we completed the remaining commitment exploration well in January 2011.

In Block 31, which is operated by BP, a total of 31 exploration wells have been drilled. We are working to mature existing discoveries into future developments on the remaining acreage.

In Block 15/06, which is operated by ENI, several exploration and appraisal wells have been drilled this year.

In Block 15, work is being initiated to mature existing discoveries as tie-ins to existing infrastructure.

In Block 17, appraisal drilling was carried out in 2011 and is expected to continue into 2012.

Block 34 was relinquished in 2011 after completion of the committed work programme.

3.2.4.2.3 East Africa

Statoil is the operator for two large frontier offshore blocks in the East Africa region - block 2 in Tanzania and area 2&5 in Mozambique. The blocks have water depths of between 1,000 and 3,000 metres.

Tanzania

Block 2 Tanzania (5,500 square kilometres): Statoil is the operator with a 65% share, while ExxonMobil is a partner and has a 35% share. Statoil announced in February 2012 that it had made a significant gas discovery in the Zafarani exploration well. This well fulfills our commitment in the current exploration phase. Following the completion of this well, we intend to drill an exploration well on the Lavani prospect. Tanzania Petroleum Development Corporation (TPDC) has the right to a 10% working interest in case of a development phase.

Mozambique

Area 2&5 Mozambique (7,800 square kilometres): Statoil is the operator with a 90% interest. The area consists of two blocks under one licence agreement. The state oil company Empresa Nacional de Hidrocarbonetos (ENH) has a 10% interest. We entered the third exploration phase on 1 June 2011 with one well commitment. A 3D survey was started in mid-November 2011. It was completed in early January 2012.

3.2.4.3 Middle East and North Africa

We have exploration licences in Libya and Iran.

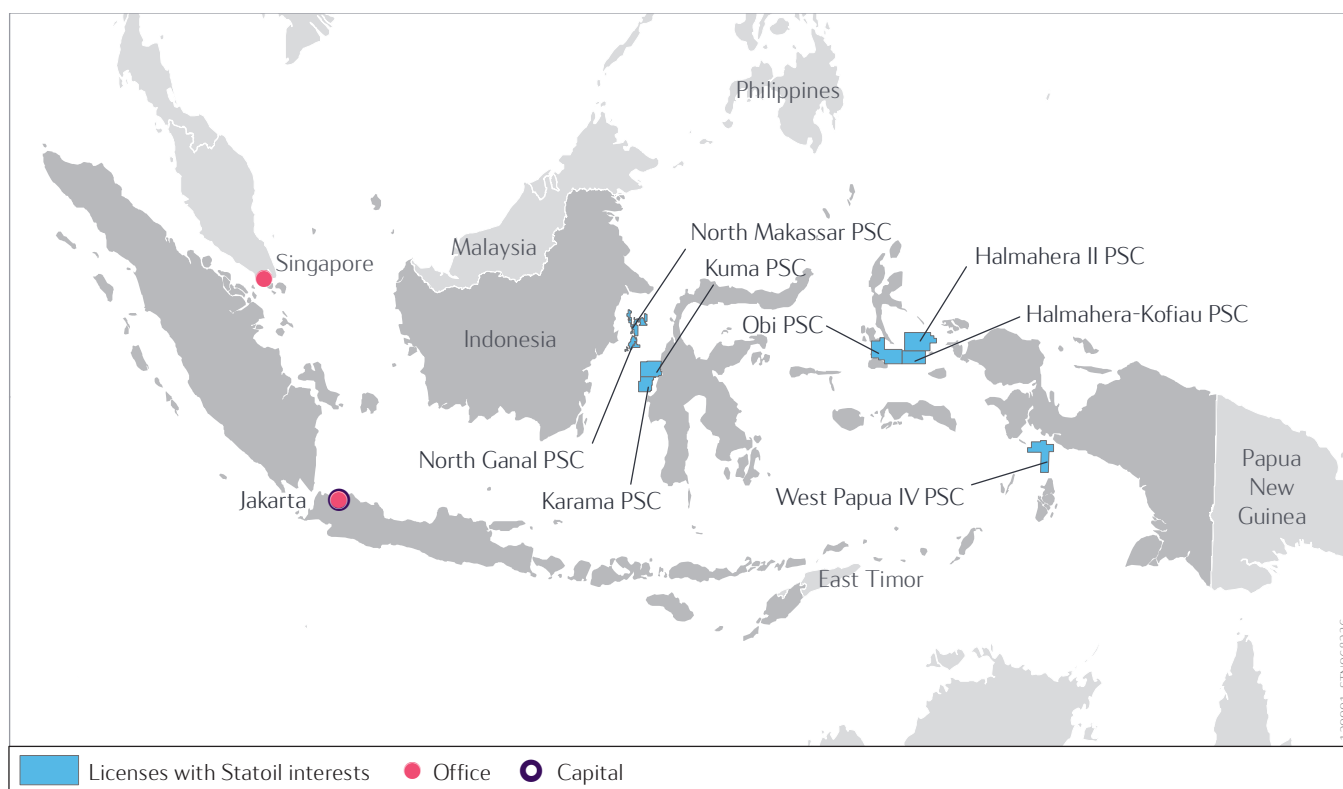
However, the company will not make any future investments in Iran under the present circumstances (see the section *International Fields - Middle East and North Africa - Iran*). Our two licences in Egypt, El Dabaa and Ras el-Hekma, expired in 2011, after completion of the committed work programme. We drilled one well in the El Dabaa licence, which was dry. Final closing is ongoing.

3.2.4.4 Europe and Asia

We have exploration licences in the Faroes, Greenland, the UK, Azerbaijan and Indonesia.

3.2.4.4.1 Indonesia

Statoil has interests in eight production-sharing contract (PSC) licences in Indonesia. We operate Karama and Halmahera II, and are partners in Kuma, North Ganai, North Makassar, West Papua IV, Obi and Halmahera Kofiau.



We acquired interests in six licences during 2011. The North Ganai and North Makassar PSCs are located in the North Makassar Strait. The West Papua IV, Obi, Halmahera Kofiau and Halmahera II PSCs are located in the eastern part of Indonesia.

We are the operator of Halmahera II PSC. Eni is the operator of North Ganai PSC, while Niko Resources is the operator of the remaining licences. We have a commitment to drill one well in the North Makassar PSC and one in the North Ganai PSC. We only have commitments to conduct seismic surveys in the other PSC.

One well in the Kuma PSC was drilled in 2011 and the result is still under evaluation. A seismic acquisition programme was started in 2011 and is expected to continue into 2012. Three wells in the Karama PSC and one well in the North Makassar PSC are planned to be drilled during 2012.

3.2.5 International production

In 2011, Statoil's petroleum production outside Norway amounted to an average of 334 mboe per day of entitlement production and 534 mboe per day of equity production.

Our total annual entitlement production in 2011 was approximately 334 mboe per day, compared with approximately 332 mboe per day in 2010.

The first table below shows DPI's average daily entitlement production of liquids and natural gas for the years ending 31 December 2011, 2010 and 2009.

Entitlement production	For the year ended 31 December		
	2011	2010	2009
Oil and NGL (mboe per day)	252	263	283
Natural gas (mmcm per day)	13	11	12
Total (mboe per day)	334	332	357

The table below provides information about the fields that contributed to production in 2011.

Field	Statoil's equity interest in per cent	Operator	On stream	License expiry	Average daily equity production mboe/day	Average daily entitlement production mboe/day
North America					93.6	93.6
Canada: Hibernia	5.00%	HMDC	1997	2027	7.9	7.9
Canada: Terra Nova	15.00%	Suncor	2002	2022	6.5	6.5
Canada: Leismer Demo ⁽¹⁾	60.00%	Statoil	2010	HBP ⁽²⁾	6.1	6.1
USA: Lorient	30.00%	Noble	2006	HBP	0.5	0.5
USA: Front Runner	25.00%	Murphy Oil	2004	HBP	1.8	1.8
USA: Spiderman Gas	18.33%	Anadarko	2007	HBP	4.0	4.0
USA: Q Gas	50.00%	Statoil	2007	HBP	0.0	0.0
USA: San Jacinto Gas	26.67%	ENI	2007	HBP	0.0	0.0
USA: Zia	35.00%	Devon	2003	HBP	0.1	0.1
USA: Seventeen Hands	25.00%	ENI	2006	HBP	0.0	0.0
USA: Marcellus shale gas ⁽³⁾	32.50%	Chesapeake	2008	HBP	28.7	28.7
USA: Eagleford shale ⁽³⁾	50.00%	Talisman	2010	HBP	5.2	5.2
USA: Tahiti	25.00%	Chevron	2009	HBP	27.5	27.5
USA: Thunderhawk	25.00%	Murphy Oil	2009	HBP	3.2	3.2
USA: Bakken ⁽⁴⁾	100.00%	Statoil	2011	HBP	2.2	2.2
South America and sub-Saharan Africa					254.2	140.8
Brazil: Peregrino	60.00%	Statoil	2011	2034	15.7	15.7
Venezuela: PetroCedeño ⁽⁵⁾	9.68%	PetroCedeño	2008	2032	13.6	13.6
Angola: Girassol/Jasmim	23.33%	Total	2001	2022	30.8	9.8
Angola: Dalia	23.33%	Total	2006	2024	54.8	17.0
Angola: Rosa	23.33%	Total	2007	2022	19.5	9.1
Angola: Pazflor	23.33%	Total	2011	2030	8.7	7.8
Angola: Kizomba A	13.33%	ExxonMobil	2004	2026	15.0	4.0
Angola: Kizomba B	13.33%	ExxonMobil	2005	2027	20.4	5.8
Angola: Xikomba	13.33%	ExxonMobil	2003	2027	0.2	0.6
Angola: Marimba North	13.33%	ExxonMobil	2007	2027	3.0	0.9
Angola: Mondo	13.33%	ExxonMobil	2008	2029	9.3	4.8
Angola: Saxi-Batuque	13.33%	ExxonMobil	2008	2029	10.9	6.5
Angola: Block 4/05	20.00%	Sonangol P&P	2009	2026	3.4	3.2
Nigeria: Agbami	20.21%	Chevron	2008	2024	48.9	42.1
Middle East and North Africa					71.4	39.5
Algeria: In Salah	31.85%	Sonatrach/BP/Statoil	2004	2027	41.1	20.5
Algeria: In Amenas ⁽⁶⁾	45.90%	Sonatrach/BP/Statoil	2006	2022	23.5	14.0
Iran: South Pars	37.00%	POGC	2008	2012	4.2	4.2
Libya: Mabruk ⁽⁶⁾	12.50%	Total	1995	2028	0.6	0.2
Libya: Murzuq ⁽⁶⁾	10.00%	Repsol	2003	2032	2.0	0.6
Europe and Asia					114.9	60.2
Azerbaijan: ACG	8.56%	BP	1997	2024	61.5	18.1
Azerbaijan: Shah Deniz	25.50%	BP	2006	2031	39.0	31.0
Russia: Kharyaga	30.00%	Total	1999	2032	8.9	5.7
UK: Alba	17.00%	Chevron	1994	2018	4.3	4.3
UK: Jupiter	30.00%	ConocoPhillips	1995	2012	0.4	0.4
UK: Schiehallion	5.88%	BP	1998	2017	0.8	0.8
Total Development and Production International (DPI)					534	334

⁽¹⁾ Statoil has sold a 40% interest in the oil sands project to PTTEP of Thailand with a valuation date of 1 January 2011. The transaction was closed in January 2011. We act as Managing Partner and retain 60% ownership of the partnership holding the oil sands project and continue to be operator of the project.

⁽²⁾ Held by Production (HBP): A company's right to own and operate an oil and gas lease is perpetuated beyond its original primary term, as long thereafter as oil and gas is produced in paying quantities. In the case of Canada, besides continue being in production status, other regulatory requirements must be met.

⁽³⁾ Statoil's average working interest (WI) for the asset. Actual WI can vary depending on wells.

⁽⁴⁾ In December 2011, Statoil acquired 100% of the outstanding shares of Brigham Exploration Company.

⁽⁵⁾ PetroCedeño is a non-consolidated company.

⁽⁶⁾ In Amenas, Mabruk and Murzuq - Statoil's reported share of equity production in these fields were adjusted in 2011 to reflect the current financing share of our investments.

The table below shows equity and entitlement production per country in 2011.

Country	Average daily equity production ⁽¹⁾ mboe/day	Average daily entitlement production ⁽²⁾ mboe/day
North America	93.6	93.6
Canada	20.5	20.5
USA	73.2	73.2
South America and sub-Saharan Africa	240.6	127.2
Brazil	15.7	15.7
Angola	176.0	69.4
Nigeria	48.9	42.1
Middle East and North Africa	71.4	39.5
Algeria	64.6	34.5
Iran	4.2	4.2
Libya	2.6	0.8
Europe and Asia	114.9	60.2
Azerbaijan	100.5	49.1
Russia	8.9	5.7
UK	5.5	5.5
Total Development and Production International (DPI)	521	321
Equity accounted production		
Venezuela: Petrocedefio ⁽³⁾	13.6	13.6
Total Development and Production International (DPI) including share of equity accounted production	534	334

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

⁽²⁾ Entitlement production figures are after deductions for royalties, production sharing and profit sharing.

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

3.2.6 International fields

Major efforts are under way to make the transition from a mainly Norwegian offshore player to a world-class international operator.

DPI is working continuously to develop the inventory of projects into producing assets by looking at innovative technical and commercial solutions.

This section covers projects under development and fields in production. Significant pre-sanctioned projects, including some discoveries in the early evaluation phase, are also presented. A field's plateau production is often referred to in this section. It means the yearly average equity production at plateau for a field for a 100% ownership share. Capacities also refer to the whole field or facility.

Exploration activities are described in the report section *Operational review - Development and Production International (DPI) - International exploration*.

Sanctioned projects coming on stream 2012-2014 *	Statoil's share	Operator	Time of sanctioning	Production start
Angola: PSVM	13.33%	BP	2008	2012
Angola: Kizomba satellites phase 1	13.33%	ExxonMobil	2009	2012
USA: Caesar Tonga	23.55%	Anadarko	2009	2012
USA: Tahiti phase 2	25.00%	Chevron	2010	2013
Ireland: Corrib	36.50%	Shell	2003	2014
Angola: CLOV	23.33%	Total	2010	2014

* Not exhaustive

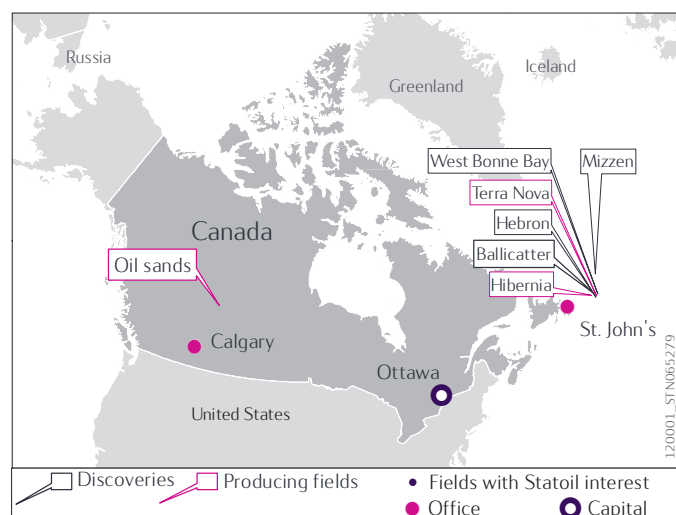
3.2.6.1 North America

Statoil's development and production activities in North America comprise interests and operations in several areas and basins.

Statoil has activities in the US Gulf of Mexico, the Appalachian region, south-west Texas, the Williston Basin, off the East Coast of Canada and in the oil sands of Alberta, Canada. We also have a representative office in Mexico City.

3.2.6.1.1 Canada

The oil sands business remains an important long-term investment, and the Leismer Demonstration Project has been operational since early 2011. Offshore, we have production interests in Hibernia and Terra Nova, and interests in two development projects.



Oil sands

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. In January 2011, we formed a joint venture with PTTEP of Thailand and, as part of that transaction, sold them a 40% interest in the leases. We continue to be managing partner, operator and 60% owner of the oil sands project.

The Leismer Demonstration Project started its first commercial production on 11 January 2011, and it produced approximately 3.7 mmbbls of bitumen in 2011. All of the project's production wells have been drilled and completed, with all four well pads in steam-assisted gravity drainage (SAGD) production mode. The Leismer Demonstration Project is connected to the existing pipeline infrastructure at our Cheecham terminal, which connects to a third-party pipeline that runs to the Edmonton area. In 2011, production ramp-up and operational performance exceeded our prior expectations.

Our second oil sands development, Corner, is currently in an early stage of development.

To determine the extent of the exploitable oil sands deposits in Alberta, more than 872 wells were drilled in the region from 2003 to 2011. Extensive seismic surveys were also carried out during the same period.

During the 2010-2011 winter drilling programme, 126 wells were drilled for the purpose of further delineation of the oil sands reservoirs, for the observation and monitoring of production operations, and for water source/ water disposal for both near and longer-term development projects. A total of 182.7 square kilometres of 3D seismic was also shot during the winter of 2010-2011. Drilling activities will continue during the 2011-2012 winter evaluation programme, along with 3D and 4D seismic coverage.

Offshore fields in production

Hibernia produces from a gravity-based structure (GBS). It is operated by Hibernia Management and Development Company Ltd (HMDC). The Hibernia field is in the initial stages of decline, with gross production rates averaging 154,000 barrels of oil per day (Statoil 5%) in 2011.



Terra Nova

Terra Nova produces from an FPSO and is operated by Suncor Energy. The Terra Nova field is also in decline, with gross production rates averaging 43,000 barrels of oil per day (Statoil 15%) in 2011. One development well was delivered in 2011, with positive results. Development drilling of the field is planned to continue in 2012. Terra Nova production was limited in 2011 due to the occurrence of hydrogen sulphide (H₂S) in the producing reservoir. The partnership plans to execute a major off-station capital programme in 2012 to remediate the H₂S issue.

Offshore development projects

The **Hebron** field, which is operated by ExxonMobil, will be developed using a GBS. The project has entered the front-end engineering design (FEED) phase. Statoil holds a 9.7% interest in the development project.

The **Hibernia Southern Extension Unit**, which is operated by ExxonMobil, comprises the development of resources in several fault blocks to the south of the existing Hibernia field. The field is planned for development as a satellite to the Hibernia field. Statoil's unitised interest is currently 10.5%. The project achieved early delivery of two producing wells in 2011. The development part of the project, which consists of the installation of a

subsea template for water injection, has been sanctioned by the partnership and is expected to be on stream in 2014. Production from the producing wells will be limited until the development is completed.

3.2.6.1.2 USA

The onshore Marcellus and Eagle Ford shale gas investments became key contributors to our North American production. Offshore, the USA continues to deliver production expectations and to progress a strong pipeline of Gulf of Mexico development projects.



Marcellus well pad

Onshore

The **Marcellus** shale gas play is located in the Appalachian region in north-east USA. In November 2008, we entered into a strategic alliance with Chesapeake Energy, 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 over 689,000 acres at the end of 2011. 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's daily equity production was 28,700 boe from 300 wells by year-end 2011.

Our joint venture acreage is concentrated around the developing core regions, most notably north-east Pennsylvania (PA), south-west Pennsylvania and north-west West Virginia (WV). We have engaged in a number of trades and purchases to consolidate our position in these areas. We see encouraging signs concerning estimated ultimate recovery rates (EUR), very strong initial production rates from north-east PA, and above pro-forma production rates in south-west PA and WV, with an upside on

liquids. Statoil and Chesapeake will continue to acquire high-grade acreage around the most prospective areas of the play and will build up production from the areas. The operator was running 23 rigs in the play at the end of 2011.

Through agreements with Enduring Resources, LLC and Talisman Energy Inc., Statoil acquired 67,000 net acres in the **Eagle Ford** shale formation in south west Texas in 2010. Statoil and Talisman formed a 50/50 joint venture for the purpose of developing assets in the Eagle Ford shale formation. Together, Statoil and Talisman initially held 134,000 net Eagle Ford acres and associated assets and production in the joint venture. The venture has continued to acquire acreage within the play, with a net acreage position of over 87,974 acres at the end of 2011. Statoil's daily equity production was 5,200 boe by the end of 2011 from 100 wells. The operator was running ten rigs in the play at the end of 2011.

The acquisition of Brigham Exploration Company, which was finalised in December 2011, gives Statoil strategic exposure to US unconventional plays, which are believed to contain a substantial resource base and represent an increasingly important part of future energy supplies. Statoil's daily equity production was 26,200 boe for December. For more information on the acquisition, please refer to the section Global Strategy and Business Development (GSB) Key events in 2011.

Offshore Gulf of Mexico

Statoil's production from the Gulf of Mexico is anticipated to increase in the next few years as a result of incremental production from development fields, despite the decline experienced in the producing fields.

Fields in production

Production started in May 2009 from the Chevron-operated **Tahiti** oilfield in which we have a 25% interest. The field is located in Green Canyon blocks 640/596. It consists of seven wells in three locations connected to a floating facility with a processing capacity of approximately 155,000 barrels of oil per day. Gross average daily production was 110,000 boe in 2011. The second phase of the Tahiti development, which will mitigate the decline from the initial phase, was sanctioned in 2010 and is now in the execution phase.

Production started in July 2009 from the **Thunder Hawk** oilfield located in Mississippi Canyon block 734. We have a 25% interest in this Murphy Oil-operated development, which consists of a semi-submersible floating production facility located in Mississippi Canyon block 736. The processing capacity is approximately 45,000 boe/d. The gross average daily production is declining and was 12,900 boe in 2011. A fourth well has been approved by the partners. It is expected to be in production by the middle of 2012.

Spiderman, a deepwater gas field, is part of the Anadarko-operated Independence Hub, which is a floating production facility located in Mississippi Canyon block 920. Statoil has an 18.3% interest in the field. The gross average daily production in 2011 was approximately 22,000 boe/d. The Independence Hub is owned by third parties. It has a processing capacity of approximately one billion cubic feet of natural gas per day. Statoil has contractual rights to 12.7% of the total capacity through May 2012 and 6.4% for five years thereafter.

The Murphy-operated **Front Runner** oilfield is located in Green Canyon blocks 338/339/382. Statoil has a 25% interest in Front Runner, which started production in 2004. The field produces while carrying out simultaneous drilling activities from a rig situated on a spar floating production facility. Gross average daily production was 7,000 boe/d in 2011.

In addition Statoil has a 30% interest in the Noble Energy-operated **Lorien** oilfield located in Green Canyon block 199, and 35% in **Zia**, located in Mississippi Canyon block 299.

Fields under development

Statoil has a 23.6% working interest in the Anadarko Petroleum-operated **Caesar Tonga** Unit in Green Canyon block 683. Development of the four-block unit was sanctioned in 2009 as a four-well subsea tie-back to Anadarko's Constitution platform. First production at the Caesar Tonga development in the Green Canyon area of the deep-water Gulf of Mexico was on 7 March 2012. Current Production is approximately 40,000 barrels of oil equivalent (BOE) per day from the first three subsea wells in about 5,000 feet of water. A fourth development well is expected to be drilled and completed later this year as part of the planned phase one development.

Tahiti Phase 2 will add two producing and three water-injection wells to the existing architecture. Injection from the first two water-injection wells is expected to start in the first quarter 2012, while first oil from additional producers is expected in the first quarter 2013.

Statoil has a 25% working interest in the **Jack** oilfield, located in Walker Ridge blocks 758/759, and a 21.5% working interest in **St. Malo**, located in Walker Ridge block 678. St. Malo and Jack are located at a water depth of approximately 2,000 metres and are approximately 40 kilometres apart. The two fields are operated by Chevron and will be developed jointly with subsea wells connected to a centrally-located production platform. The Jack and St. Malo projects were sanctioned in September 2010 and the 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. The Big Foot project was sanctioned in December 2010. The first oil from Big Foot is scheduled in late 2014.

Discovered in 2007, **Julia** (ExxonMobil 50% and Statoil 50%) is one of the major discoveries in Paleogene, with a significant in-place volume. In October 2008, ExxonMobil (operator) filed for Suspension of Production (SOP) based on a subsea tie-back concept or, alternatively, a stand-alone facility; which was denied by Minerals Management Service (now Bureau of Ocean Energy Management - BOEM). In May 2011 the Director of Hearing and Appeals ("OHA") issued a decision upholding BOEM's SOP denial and overruling the prior Interior Board of Land Appeals ("IBLA") decision (2009), which was in favour of the Julia partners. In August 2011, Statoil and ExxonMobil filed separate appeals in the federal court system challenging the OHA Director's decision. In parallel, Julia owners were engaged in settlement negotiations with the Department of Interior (DOI) and Department of Justice (DOJ) to resolve the SOP issues. At the same time, the Julia partners negotiated with the Jack and St Malo partners to secure an amendment to the production handling agreement (PHA) for Julia's re-entry into the Jack and St Malo host. A settlement agreement was signed with DOI and DOJ at the end of December 2011. On 18 January 2012, the US District Court signed and filed its Order approving the Julia settlement and dismissed the case. The settlement is final. In early January 2012, the PHA amendment was also signed by the Jack and St Malo host owners and Julia partners. ExxonMobil, operator for Julia, is gearing up and plans to restart the project in the second quarter of 2012. The first oil is expected by mid-2016.

3.2.6.2 South America and sub-Saharan Africa

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

3.2.6.2.1 Brazil

Statoil is the operator of the Peregrino offshore field, which started production in April 2011. We are among the largest foreign offshore operators in Brazil in terms of production.



Peregrino

The Peregrino field is a heavy oil field located in approximately 120 metres of water in the prolific Campos Basin, about 85 kilometres off the coast of Rio de Janeiro.

The field came on stream on 9 April 2011. It is producing the oil from two well head platforms with drilling capability to an FPSO for final processing. Our share of the production was 15.7 mboe per day in 2011. Design capacity is 100,000 barrels of oil per day.

In May 2010, Statoil agreed to form a joint venture and sell 40% of the Peregrino field to Sinochem Group. Statoil retained 60% ownership, and operatorship of the field. The transaction was formally signed on 14 April 2011 after being approved by the Brazilian government.

Work is also ongoing to develop the Peregrino South and South West discoveries.

3.2.6.2.2 Venezuela

Statoil has a 9.7% interest in Petrocedeño, one of the largest extra-heavy crude oil projects in Venezuela.

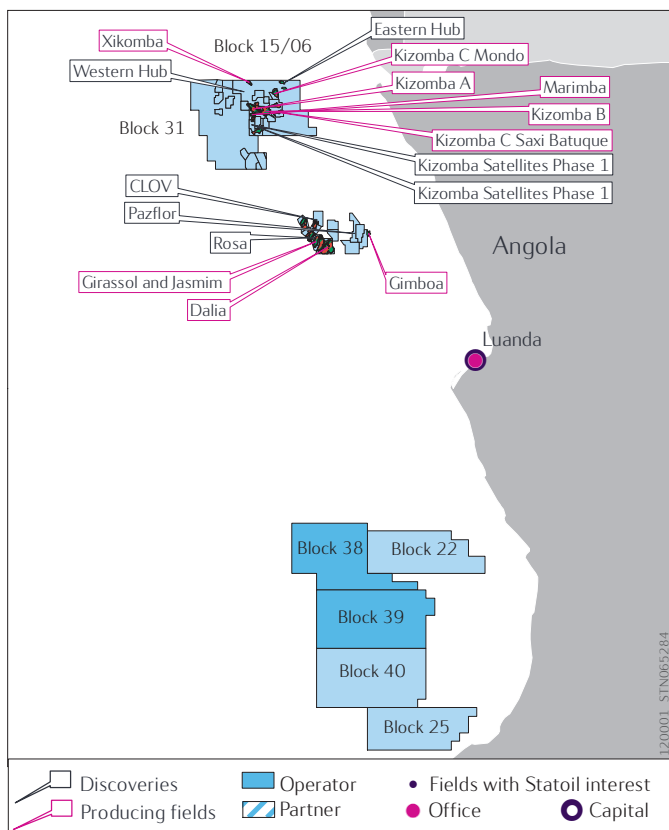
The Petrocedeño project involves the extraction of extra-heavy crude oil from reservoirs in the Orinoco Belt. A diluting component is added in order to enable the extra-heavy crude oil to be transported by pipeline to the coast, where it is upgraded to a light, low-sulphur syncrude destined for the international market. Petrocedeño, S.A, which is owned by project partners PDVSA, Total and Statoil, operates the field and markets the products.

Statoil's share of Petrocedeño production in 2011 was 13.6 mboe per day, which is below design capacity. A recovery programme is ongoing to improve the situation.

We have been present in Venezuela since 1994 and have a long-term commitment to the country based on the participation in Petrocedeño and Venezuela's large oil reserves.

3.2.6.2.3 Angola

The Angolan continental shelf is the largest contributor to Statoil's production outside Norway. It yielded 176 mboe per day in equity production in 2011, 33.0% of Statoil's total international oil and gas output.



Block 17 is operated by Total. Our interest is 23.3%. Production from the block currently comprises five development areas produced over three FPSOs. The **Girassol**, **Jasmim** and **Rosa** development areas are produced over the Girassol FPSO and the **Dalia** development area over the Dalia FPSO. This year, the **Pazflor** development came on stream, producing to the Pazflor FPSO. The combined equity production from block 17 was 113.9 mboe per day in 2011.

The **Pazflor** project, which comprises the *Perpetua*, *Acacia*, *Zinia* and *Hortensia* discoveries, came on stream on 24 August 2011. The expected production capacity of the FPSO is 220 mboe per day.

The **CLOV** project consists of the *Cravo*, *Lirio*, *Orchidea* and *Violeta* discoveries. The project was sanctioned in mid-2010 and it is currently under development. CLOV will be produced over a new FPSO, with an expected production capacity of 160 mboe per day. The first oil is expected in 2014.

An IOR initiative to fill excess capacity on the Girassol FPSO was implemented in 2011. Additional projects are under development on block 17. The IOR projects include subsea tie-backs, infill wells, and the use of multi-phase pumps.

Block 15 is operated by Esso Angola, a subsidiary of ExxonMobil. Our interest is 13.3%. Statoil's equity production from block 15 was 58.8 mboe per day in 2011. Production here stems 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. The **Xikomba** FPSO ceased production in March 2011. It is now being decommissioned.

Kizomba Satellites phase 1, consisting of two discoveries, *Clochas* and *Mavacola*, was sanctioned by the partnership in 2009. It is currently under development. The first oil is scheduled for 2012.

Possible development of the **Kizomba Satellites phase 2** is being evaluated. The project includes the *Bavuca*, *Kakocha* and *Mondo South* discoveries.

Block 31 is an ultra-deepwater licence operated by BP. Our interest is 13.3%. The development of the first four discoveries in the northern part of the block - *Plutao*, *Saturno*, *Venus* and *Marte* (**PSVM**) - was approved by the concessionaire in July 2008, and it is now under execution. PSVM will be developed via a new FPSO with a production capacity of 150 mboe per day. The first oil is scheduled for 2012. Work is also ongoing to pursue a second development in the southern part of block 31.



Kizomba A

Block 4/05 is operated by Sonangol P&P, and Statoil's interest is 20%. This block includes the **Gimboa** field. The equity production was 3.4 mboe per day in 2011.

Block 15/06 is operated by Eni, and Statoil's interest is 5%. Work is currently being done to progress a development solution for the discoveries on the block.

Gas Gathering Projects: Pursuant to the production sharing agreement (PSA), all surplus gas from the fields in Angola is to be delivered to Sonangol, which owns the gas. No income will be generated from the transfer of gas, and costs and investments related to the projects will be recovered through the PSA.

The delivery of commissioning gas from block 15 to the Angola LNG Terminal started in the second quarter of 2011. The export of gas from block 17 with injection into block 2 started in December 2010. The pipeline from block 2 to the Angola LNG Terminal was completed in 2011. It is ready to start deliveries to the terminal.

3.2.6.2.4 Nigeria

In Nigeria, we have a 20.2% interest in the largest deep water producing field, Agbami.



Agbami

The Agbami field is produced from subsea wells connected to an FPSO. It is located about 110 kilometres off the coast of Nigeria and is operated by Chevron. The field is producing close to the nominal plateau rate of 250 mboe per day.

The National Assembly is still debating the Petroleum Industry Bill (PIB), which will most likely increase the government take if passed.

Together with our partner Chevron we are currently in arbitration with the national oil company NNPC over the interpretation of certain clauses in the production sharing contract (PSC) that governs our share of Agbami.

The security situation in Lagos and the rest of south west Nigeria is normally medium to high depending on the time of day. While the kidnapping of middle- to high-income Nigerians does take place, it is relatively rare. Robberies and car snatching are more common place. There is, however, an increase in piracy and other waterborne crime. There has been no impact on large crude oil tankers in 2011. Convoy and security

vessels are used to protect supply ships and other smaller vessels. Kidnappings are on the rise in the Delta area in the south. The security situation is similarly serious in the north east.

3.2.6.3 Middle East and North Africa

Statoil's development and production in the Middle East and North Africa in 2011 primarily encompassed Algeria, Libya, Egypt, Iran and Iraq.

In this region, Statoil is active as a joint operator in the producing fields In Salah and In Amenas in Algeria. The upstream assets in Algeria supplement Statoil's strong position as a supplier to the European gas market. In 2011, Statoil has been an active partner in licences in Libya and Iraq and it was also the operator for two exploration licences in Egypt in 2011.

Due to the political situation in Libya, Statoil's Libyan operations and production were stopped in February 2011. The Murzuq field resumed production on 13 November 2011 and the Mabruk field resumed production on 12 January 2012.

Statoil also has offices in Abu Dhabi and Iran.

3.2.6.3.1 Algeria

Our main assets, In Salah and In Amenas, are the third-largest and fourth-largest gas developments in Algeria. The developments of the In Salah Southern Fields and In Amenas Gas Compression Project were sanctioned in 2010.

Fields in production

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, and compression has started on all three fields.



In Amenas

The **In Amenas** onshore development is the fourth-largest gas development in Algeria. It contains significant liquid volumes. Production efficiency is high, although occasional capacity restrictions due to priorities in the export pipeline system remain an issue.

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%. Production has reached plateau level. The rights and obligations are governed by a production sharing contract that gives BP and Statoil access to a share of the liquid volumes. A continuous production drilling campaign is ongoing.

Fields in development

The **In Salah Southern Field Development Project** was sanctioned in late 2010. This project will mature the remaining four discoveries into production. It is planned to come on stream in the first half of 2014. The southern fields will tie in to existing facilities in the northern fields.

The **In Amenas Gas Compression Project**, which is led by BP, was sanctioned in late 2010. The compressors are expected to come on stream early in 2013. This will make it possible to reduce well head pressure and maintain the contractual production commitment.

The **Hassi Mouina** exploration phase has been extended until September 2012. Statoil is currently assessing the technical solutions for and the commercial attractiveness of a potential development.

3.2.6.3.2 Iran

Statoil was the offshore operator for the development of phases 6, 7 and 8 of the South Pars gas and condensate field in the Persian Gulf until its completion in 2009. Statoil will not make any future investments in Iran under the present circumstances.

The National Iranian Oil Company (NIOC) took over as the formal operator of South Pars after its completion. Statoil assisted the NIOC for a limited transitional period in accordance with the contractual framework for the development phase. The technical service agreement (TSA) concluded at the end of March 2011, in accordance with the contract.

Statoil has previously taken part in exploration and drilling activities in the country on the Anaran block. Work on this project has been stopped. Statoil also holds a licence for exploration of the Khorramabad block. No activity is planned for this licence.

A small staff is working to secure the outstanding contractual cost recovery and remuneration for Statoil for the development and exploration contracts. Considerable progress has been made during 2011.

In a letter from the US Department of State dated 1 November 2010, Statoil was informed that the company is no longer considered to be a company of concern with regard to its previous Iran-related activities, since the Secretary of State chose to apply the "Special Rule" in the Comprehensive Iran Sanctions, Accountability and Divestment Act of 2010.

See the section *Risk review - Risk factors - Risks related to our business* for additional information about the risk of sanctions relating to activities in Iran.

3.2.6.3.3 Libya

Due to political unrest in February 2011, Statoil's operations were suspended in Libya. Work is now ongoing to restore production in full on the Murzuq and Mabruk oil fields.



Murzuq basin

Due to the outbreak of political unrest in Libya, Statoil's Libyan operations were suspended in February 2011 and the fields stopped production on 21 February (Murzuq) and 26 February (Mabruk). Statoil's office in Libya was closed on 20 February 2011. All Statoil expatriate staff and their families were safely evacuated from the country. The local staff were paid wages during the unrest and, as order was restored, they were involved in the reestablishment of the office in the capital, Tripoli. The office was opened on 20 March 2012.

The **Murzuq** field resumed production on 13 November 2011. The NC 186 licence in the Murzuq area consists of seven fields (A, B, D, H, I/R, J and K). Akakus Oil Operations is the operating company for the Murzuq NC 186 license, with Repsol as the lead partner for the international oil companies. Statoil's share of investments (working interest) in the NC 186 license in the Murzuq field is 10%. The oil from the Murzuq fields is transported by pipeline to the Az Zawia terminal west of Tripoli for lifting by ship.

The **Mabruk** oilfield resumed production in January 2012. The field is located in licence C-17 in the Sirte basin. Mabruk Oil Operations is the operating company for the Mabruk C-17 license, with Total as the lead partner for the international oil companies. Statoil's share of investments (working interest) in the c-17 license in the Mabruk field is 12.5%. The field has been producing since 1995. The Dahra south-east project was sanctioned in 2009.

Work to fully restore production is ongoing in both areas.

3.2.6.3.4 Iraq

In 2010, Statoil and Lukoil entered into an agreement with the Iraqi authorities for the development of the West Qurna 2 field. However, Statoil has now started the process of transferring its 18.75% share to Lukoil.

The parties to the contract were the Iraqi state's South Oil Company and a consortium of contractors consisting of the Iraqi state's North Oil Company (25% and state partner), Lukoil, (56.25% and operator) and Statoil (18.75%). The development and production service contract for the West Qurna 2 field was offered as a service contract under which the contractors receive cost recovery plus a remuneration fee. Lukoil and Statoil's bid for West Qurna 2 included a production plateau level of 1,800 mboe per day.

However, Statoil has agreed with Lukoil and the Iraqi authorities to start the process of transferring its 18.75% share in the West Qurna 2 development project to the operator Lukoil. The booked reserves have been adjusted accordingly.

3.2.6.4 Europe and Asia

Development and Production in Europe and Asia primarily comprises Azerbaijan, Russia, United Kingdom and Ireland.

Statoil is active in several partner-operated licences in this region, including the major producing fields Shah Deniz and Azeri-Chirag-Guneshli in Azerbaijan. The upstream assets in Azerbaijan are a significant supplement to Statoil's strong position as a supplier to the European gas market. Statoil is also a partner

in the Shtokman gas field in Russia, together with Gazprom and Total. Shtokman is a long-term resource that can enhance our upstream gas position while making Statoil a supplier from the north east. In the United Kingdom, Statoil has several oilfields under appraisal and it holds interests in three producing fields.

3.2.6.4.1 Azerbaijan

Statoil has been present in Azerbaijan since 1992, and has invested more than USD 5 billion. The two fields Azeri-Chirag-Gunashli and Shah Deniz contribute around 100 mboe per day of equity production to Statoil.



Shah Deniz

Statoil has a 8.6% stake in the Azeri-Chirag-Gunashli (ACG) field and an 8.7% stake in the 1,760-km Baku-Tbilisi-Ceyhan (BTC) pipeline that is used to transport most of ACG oil to the southern Turkish port of Ceyhan, enabling Azeri crude to be shipped to the world markets. The ACG field is operated by BP and is governed by a production sharing agreement (PSA) signed in 1994 with a duration of 30 years. In 2011, the field produced an average of 718 mboe per day.

The Chirag Oil Project sanctioned by the ACG partnership in 2010 is progressing according to plan. The first production from this project is scheduled for late 2013, and it is planned to add some 185 mboe per day in new production to ACG.

In addition to the share in ACG, Statoil has a 25.5% share in the Shah Deniz gas and condensate field, and a 25.5% share in the South Caucasus Pipeline, which transports the Shah Deniz gas from Azerbaijan through Georgia to the eastern Turkish border. The condensate from Shah Deniz is transported through the BTC pipeline to Ceyhan in Turkey. The Shah Deniz

field is operated by BP and Naftiran Intertrade Company (NICO) has a 10% interest in this field. Statoil runs the Azerbaijan Gas Sales Company, which has been established to manage gas allocation and sales to customers in Azerbaijan, Georgia and Turkey. Statoil is also the commercial operator of the South Caucasus Pipeline Company, which is responsible for the commercial operations around the South Caucasus Pipeline. Shah Deniz Phase 1 has been in production since 2006. Shah Deniz produced 115 mboe per day of gas and 38 mboe per day of condensate in 2011. The PSA expires in 2031.

In 2007, the Shah Deniz partners decided to start maturing the second phase of the Shah Deniz field development. The concept for the Shah Deniz Phase 2 field development was agreed by the partners in late 2010. Project development operator BP estimates annual production from Shah Deniz Phase 2 to be 16 bcma of gas per year and about 100 mboe per day of condensate. The current plan is to make a final investment decision around the middle of 2013. That would mean first gas from the Shah Deniz Phase 2 development in late 2017.

The licences in Alov, Araz and Sharg expired in 2011 and were handed back to the State Oil Company of Azerbaijan (SOCAR). Operator BP has not been able to do any field work on these licences, as they are located in the disputed zone between Azerbaijan and Iran.

3.2.6.4.2 Russia

Statoil has been present in Russia since the late 1980s. We have a 24% ownership interest in Shtokman Development AG, which is responsible for the Shtokman development phase one. We also have a 30% ownership interest in the Kharyaga oilfield.



The Kharyaga field

Field in production

The Kharyaga field is located onshore in the Timan Pechora basin in north-west Russia. The field is being developed under a production sharing agreement (PSA). Statoil has a 30% equity interest in Kharyaga. Kharyaga produced 8.9 mboe per day of oil in 2011.

During 2011, production has been maintained at plant capacity level. Phase 3 and the Phase 3 Extension development are ongoing, and 24 wells have been drilled.

Field under planning

The Shtokman gas and condensate field is located in the Russian Barents Sea. The agreement with Gazprom gives Statoil a 24% equity interest in Shtokman Development AG (SDAG), in which Gazprom (51%) and Total (25%) are the other two partners. The owners have seconded personnel to SDAG, which is responsible for the planning, financing, constructing and operation of the infrastructure that is necessary for the first phase of the

development. SDAG will own and operate the infrastructure for 25 years from the start of commercial production. SDAG is currently finalising the technical concept and is preparing for the execution of the first phase of the Shtokman development in accordance with the framework agreements signed in 2007. Implementation of the project is subject to a final investment decision (FID) pursuant to SDAG's plans. In December 2011, the FID was postponed until 31 March 2012.

3.2.6.4.3 United Kingdom

Statoil has several oilfields under appraisal in the United Kingdom (UK) and it holds interests in three producing fields.

Fields in production

The **Alba** oilfield, located in the central part of the UK North Sea, is operated by Chevron. Statoil has a 17% interest in this mature field. Alba produced 4.3 mboe of oil per day in 2011.

The **Schiehallion** oilfield is located west of the Shetland Islands. BP is the operator and Statoil has a 5.9% interest. In July 2011, the Schiehallion partnership sanctioned the redevelopment of the field and the acquisition of a new FPSO vessel. This is expected to extend production until at least 2035. Schiehallion produced 0.8 mboe of oil and gas per day in 2011.

Jupiter is a gas field located in the southern part of the UK North Sea. ConocoPhillips is the operator of the field, and Statoil has a 30% interest. Jupiter production is currently very low (~ 5 million standard cubic feet per day). The joint venture is discussing abandonment plans. Jupiter produced 0.4 mboe of gas per day in 2011.

Discoveries under appraisal

Statoil is the operator for and holds a 81.6% interest in **Bressay**. Statoil is also operator for Mariner (65.1% interest) and Mariner East (62.0% interest). Mariner East is a potential subsea tieback to the main Mariner platform. All three fields are heavy oil.

Rosebank, a discovery made by Chevron in 2004, is located west of the Shetland Islands. Statoil has a 30% interest in this field. The partnership is currently working towards concept selection for the field development.

3.2.6.4.4 Ireland

Statoil has a 36.5% interest in the Corrib gas field, which lies on the Atlantic Margin north-west of Ireland. The Shell-operated Corrib field development was sanctioned in 2001, and work towards the first gas is ongoing.

The project has been delayed for some years mainly due to lengthy consideration of planning applications both for the terminal and the onshore section of pipeline and a controversial challenge that Shell experienced in 2005 when a small number of local landowners refused to allow Shell E&P access to their land to proceed with construction work relating to the onshore section of pipeline.

Now the construction of the gas terminal is 95% complete and preservation work is ongoing to maintain the condition of the equipment pending commissioning. Planning permission and other governmental consents for the tunnel required to lay the onshore pipeline under the estuary were obtained during the first quarter of 2011. Work started on the tunnel launch compound in July once all preconditions had been met. Groundwork is ongoing and the civil engineering contractor has been mobilised to site.

Six subsea wells have been drilled and the pipeline from field to shore is in place. The link line connecting the terminal to the Irish gas grid is in place. Production start-up is now anticipated to take place in 2014 at the earliest.

3.3 Marketing, Processing and Renewable Energy (MPR)

3.3.1 Introduction to MPR

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

We run 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.

MPR is also responsible for marketing gas supplies originating from the Norwegian state's direct financial interest (SDFI). In total, we are responsible for marketing approximately 80% of all Norwegian gas exports.

In 2011, we sold 36.1 bcm (1.3 tcf) of natural gas from the Norwegian continental shelf (NCS) on our own behalf, in addition to approximately 33.5 bcm (1.2 tcf) of NCS gas on behalf of the Norwegian state. Statoil's total European gas sales, including third-party gas, amounted to 79.8 bcm (2.9 tcf) in 2011, of which 39.5 bcm (1.4 tcf) was gas sold on behalf of the Norwegian state. That makes us the second-largest gas supplier to Europe.

In 2011, we also sold 671 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 865,000 tonnes of methanol. Our international trading activities make us one of the world's largest net crude oil sellers.

The MPR business activities are organised in the following business clusters:

- Natural Gas
- Crude oil, liquids and products
- Processing and manufacturing
- Renewable energy

3.3.2 MPR key events 2011

In 2011, the gas market was characterised by volatility in both market prices and customer off-take. Refinery margins and trading margins were weaker than in 2010. The operation of facilities has been stable, and HSE results have improved since 2010.

- Sales of entitlement gas totalled 39.0 billion cubic metres (bcm), a decrease of 2.7 bcm compared with 2010.
- The on-stream factor (excluding Kårstø and Kollsnes) was 95.6% in 2011, compared with 91.1% in 2010. The available yearly capacity for Kårstø and Kollsnes was 93.3% in 2011, compared with 90.4% in 2010.
- Turnarounds were carried out at Tjeldbergodden, Kalundborg, Sture and Kollsnes in 2011, mainly according to plan and with good HSE performance.
- In June 2011, Statoil entered into an agreement for partial divestment of its ownership interest in Gassled, from 29.1% to 5.0%. The divested interest of 24.1% was purchased by the financial investment company Solveig Gas Norway AS. The transaction was approved by the government authorities in December 2011.
- Statoil and Centrica signed a long-term gas sales agreement for the delivery of 5 bcm gas per year to the UK market from 2015 to 2025. This new long-term gas sales agreement follows an existing agreement between Statoil and Centrica that expires in 2015.
- The first volumes were lifted from the Peregrino field in Brazil on 17 June.
- Electricity production from the Sheringham Shoal wind farm commenced in August.
- Large parts of Statoil's onshore wind power activities in Norway were sold. The transactions were closed in September.

3.3.3 Natural Gas

3.3.3.1 Natural Gas

The Natural Gas 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.

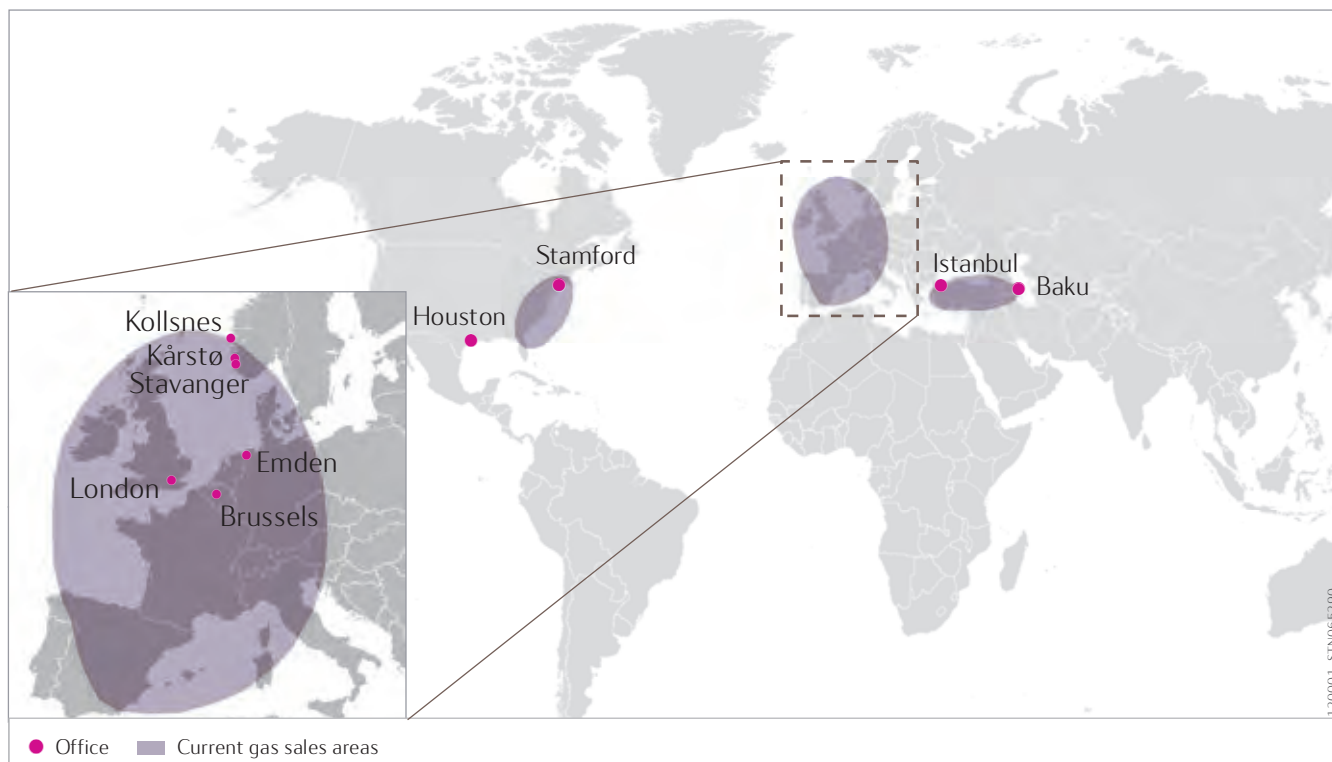
Natural Gas (NG) is also responsible for marketing gas originating from the SDFI. NG also manages Statoil's asset ownership in gas infrastructure, such as the processing and transportation system for Norwegian gas (Gassled).

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

In 2011, we sold 36.1 bcm (1.3 tcf) of natural gas from the NCS on our own behalf, in addition to approximately 33.5 bcm (1.2 tcf) of NCS gas on behalf of the Norwegian state. Statoil's total European gas sales, including third-party gas, amounted to 79.8 bcm (2.9 tcf) in 2011 of which 39.5 bcm (1.4 tcf) was gas sold on behalf of the Norwegian state.

In addition, we sold 5.5 bcm (0.2 tcf) of gas originating from our international positions, mainly in Azerbaijan and the USA, of which 2.7 bcm (0.1 tcf) was entitlement gas.

We are a significant shipper in the NCS pipeline system owned by Gassled*, which is the world's largest offshore gas pipeline transportation system, totalling approximately 8,100 kilometres. This network links gas fields on the NCS with processing plants on the Norwegian mainland and with terminals at six landing points located in France, Germany, Belgium and the UK. It thereby gives us access to customers throughout Europe.



* Statoil had a 5% ownership interest in the system at the end of 2011.

3.3.3.2 The gas market

In 2011, the nuclear accident in Japan led to greater gas power generation and higher LNG imports from European sources, while the US gas market became self-sufficient with a relatively low-cost shale gas supply.



LNG-tanker outside Melkøya

In the longer term, we believe that natural gas will be an increasingly attractive commodity. According to the *IEA World Energy Outlook 2011*, estimated global gas consumption in 2035 will be 55% higher than 2009 levels, reaching 4,750 bcm per year.

Europe

We market and sell our own gas as well as the Norwegian state's gas volumes. We also market gas sourced from producing areas other than the NCS. Other major gas suppliers to Europe are Gazprom in Russia, Sonatrach in Algeria, GasTerra in the Netherlands and, since 2010, Qatari LNG. We believe that Norwegian natural gas exports will remain highly competitive due to their reliability, access to a flexible and integrated transportation infrastructure and proximity to key European markets such as the UK, Germany and France. In addition, natural gas is an attractive source of energy from an environmental perspective since it emits far less carbon dioxide than coal and oil. During 2011, we increased our efforts to develop new marketing channels, targeting both end-user segments and power producers, resulting in new short-term and longer-term contracts.

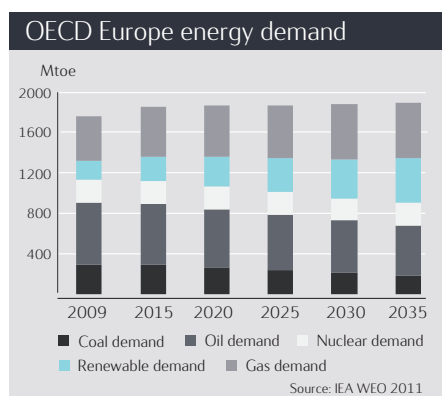
European natural gas prices were driven by a number of factors. Strong European storage injection levels coupled with the pull of LNG volumes towards Asia following the events in Japan supported prices through the summer, but a warm start to the winter of 2011-2012 contributed to low demand, relatively low winter prices and low storage withdrawals.

The interplay between coal and gas-fired power plant dispatch, which forms the basis for the coal switching price, was a key determinant of European gas prices throughout 2011. Coal prices remained relatively stable during the first three quarters of 2011 but fell by nearly USD 15/tonne in the fourth quarter of 2011 due to lack of support from Asian coal demand and concerns about economic growth weighing on commodity markets. Gas prices, in turn, remained above the coal switching price for most of the year due to the global tightness in LNG availability. The decline in coal prices, combined with a slide in carbon emissions prices, effectively meant that coal strengthened its position as the preferred fuel for power generation and reduced demand for gas. As a result, gas-to-power demand in 2011 was on average 22% lower than 2010 levels.

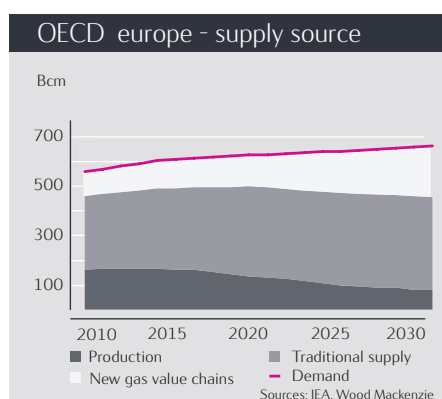
We anticipate continued high demand for LNG over the next five years and expect that the pending nuclear policy decisions in Japan and other countries with nuclear power will create uncertainty with regard to the market direction. As we believe global demand for natural gas will continue to grow, predominantly in Asia, we expect that any global LNG oversupply will diminish towards the middle of the decade as demand growth outpaces supply, despite new production capacity coming on stream. We expect European demand to grow due to increased demand for gas for power generation.

Liberalisation creates new opportunities and new business models in the gas sector, both with regard to added value as a result of efficiency gains and with regard to building a more substantial portfolio of sales directly aimed at large industrial customers and local distribution companies. Access to downstream markets has traditionally presented challenges, since capacity has been booked by incumbent companies. The Third Package (draft legislation from the EU) will introduce measures that should address capacity congestion and result in gradual improvements in market access and liquidity as the legislation is implemented across Europe. The integration of the gas and electricity markets also presents us with new business opportunities.

The EU is set to import some 75% of its natural gas by 2020 due to declining domestic gas production. In order to diversify supplies, European countries and companies are actively seeking alternative supply solutions. Moreover, Europe will need additional new sources of natural gas, since the global LNG market is expected to divert more gas to the growing Asian economies. We believe we are well positioned to supply part of this additional natural gas demand.



The gas market in OECD Europe is expected to grow from the current level of 550 bcm to approximately 630 bcm by 2030. The competitiveness of gas is expected to drive its share of total energy consumption from 25% today to 29% in 2030. Most of this growth is expected from increasing installation of gas power generation capacity.



Since the European energy markets are continuously facing changes in regulation and structures, we believe that natural gas will play an increasingly important role. We expect this trend to be reinforced as Europe pursues its long-term target of moving to a low-carbon economy, as reflected in the European Commission's "Energy Roadmap 2050".

North America

In North America, natural gas markets continued to be dominated by increasing domestic production from unconventional resources. Though demand was up again in 2011, by over 3% compared with the same period in 2010, this was almost entirely weather driven, with some increase from price-sensitive substitution of gas for coal in the power-generation sector. Even with this support, prices only traded in the USD 4-5 per million BTU range for the first three quarters of 2011, and, with the warmer weather at the end of the year, traded in the USD 3-4 range. Despite these prices, production continued to rise, increasing by 7%. Rig counts, a primary leading measure, stayed high as joint ventures and natural gas liquids yields have supported gas-directed drilling. With the relatively warm start to the winter of 2011-12 and record high storage levels, it appears that prices will continue to be under pressure throughout 2012.

The natural gas system in North America still shows few concrete signs of the structural changes in demand required to fully realise the benefits of the unconventional revolution in the USA, but there are more positive indications. The low-price environment and large global fuel spreads are incentivising new outlets for domestic gas resources. Most notable is Cheniere Energy's proposed LNG export facility, which has received an export licence, signed both off-take and construction agreements, and appears to be on track to commence operations in the 2015-16 timeframe. This would eventually make it the first such facility in the continental USA. Further plants look to have a more difficult time, due to the commercial arrangements that most proposed builders are asking off-take customers to accept, and potential export licensing headwinds. These new markets for US natural gas are needed to firm up prices, which would positively impact producers.

3.3.3.3 Gas sales and marketing

Statoil is a long-term, reliable natural gas supplier with a strong position in some of the world's most attractive markets.

Europe

The major export markets for gas from the NCS are Germany, France, the UK, Belgium, Italy, the Netherlands and Spain. The gas is mostly sold through long-term take-or-pay 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), Distrigaz and GasTerra. We also market our gas to large industrial customers, power producers and wholesalers, in addition to participating in the spot market.

Our group-wide gas trading activity is mainly focused on the UK gas market (National Balancing Point), which is a significant market in terms of size and the most liberalised market in Europe. We also take part in other liquid trading points, such as the PegN (Peg Nord) in France, TTF (Title Transfer Facility) in the Netherlands, the Zeebrugge Hub in Belgium and Gaspool/NCG in Germany.

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

In 2004, Statoil (UK) Limited and SSE Hornsea Limited (subsidiaries of Statoil and Scottish and Southern Energy Plc, respectively) entered into a joint venture for the development, operation and maintenance of a salt cavern gas storage facility near Aldbrough on the east coast of Yorkshire, near the Easington terminal. The storage facility was officially opened on 27 June 2011. It comprises nine underground caverns that have been formed by using seawater to leach out salt water deposits around two kilometres underground. Statoil (UK) Limited owns one-third of the storage capacity being developed, of which the Norwegian State's direct financial interest (SDFI) will have access to 48.3%. The facility has been developed and is operated by SSE Hornsea Limited. Six of the nine caverns at Aldbrough are already storing gas. Full commercial operation of the nine-cavern facility is scheduled for 2012. When fully commissioned, Aldbrough will have the capacity to store around 330 million cubic metres of gas.

In Germany, we hold a 30.8% stake in the Norddeutsche Erdgas-Transversale (Netra) overland gas transmission pipeline, and a 23.7% stake in Etzel Gas Storage through our subsidiary Statoil Deutschland. Etzel Gas Storage is currently increasing its working gas capacity by 10 additional caverns, one of which was completed in 2009. Eight caverns were handed over to commercial operation in 2010, and the last one was handed over in 2011. All partners in Etzel Gas Storage are participating in this project.

USA

The USA is the world's largest and most liquid gas market. Statoil Natural Gas LLC (SNG) has a gas marketing and trading organisation in Stamford, Connecticut that markets natural gas to local distribution companies, industrial customers and power producers. SNG has two long-term capacity contracts with Dominion Resources Inc., which owns the Cove Point LNG regasification terminal in Maryland. The first is for a one-third share of Cove Point capacity (LTD1), which is equivalent to approximately 3.2 bcm per year. As of 31 December 2011, the second is for 100% of the Cove Point Expansion (CPX) capacity of approximately 7.7 bcm per year. This is equivalent to a total regasification capacity of 10.9 bcm per year. This long-term capacity agreement was renegotiated in December 2010 and approved by the boards of Statoil ASA and Dominion Resources Inc. in January 2011. The agreement was approved by the US government in April 2011. As a consequence, Statoil's commitments relating to the regasification capacity at CPX have been significantly reduced.

The CPX capacity also includes downstream pipeline capacity from the Cove Point terminal to Leidy in Pennsylvania and gas storage capacity at Leidy.

Through Statoil, SDFI pays for a share of the capacity at the Cove Point regasification terminal, downstream pipeline capacity and storage capacity. LNG is sourced from the Snøhvit LNG facility in Norway and from third-party suppliers.

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

In 2008, Statoil entered into a strategic agreement with Chesapeake Energy Corporation relating to Marcellus shale gas. This strengthens Statoil's natural gas position in the USA by providing access to large gas reserves geographically near the north east, which, historically, is the highest-paying gas market. This also results in a significant increase in the volume of gas marketed and traded by Statoil in the USA.

In 2009, SNG concluded transportation agreements with Tennessee Gas Pipeline (a subsidiary of El Paso Corp) and Texas Eastern Transmission (a subsidiary of Spectra Energy Corp), ensuring Statoil the right to transport up to two bcm per year/200,000 mcf/day directly from the Northern Marcellus production area to New York City and surrounding areas. The expected in-service date is late 2013 or early 2014.

In 2010, SNG concluded a transportation agreement with National Fuel Gas Supply Corporation for up to 3.2 bcm per year (320,000 mcf/day). This agreement will enable Statoil to transport gas on a direct path from the Northern Marcellus production area to the US/Canadian border at Niagara Falls, thereby providing access to the attractive urban areas of eastern Canada. The expected in-service date is November 2012.

In December 2010, Statoil and Talisman formed a 50/50 joint venture for the purpose of developing assets in the Eagle Ford shale. SNG will market Statoil's share of the gas production. The Eagle Ford equity production is a valuable addition to Statoil's oil and gas market portfolio in North America.

In 2011, Statoil Natural Gas LLC has entered into two long-term gas sales agreements with a major Canadian gas distributor. Under both agreements, Statoil will deliver gas to our counterparty at Niagara Falls on the US-Canadian border. Our counterparty has contracted for transportation capacity on the Trans Canada Pipeline (TCPL) from Niagara Falls to the Enbridge Central Delivery Area (ECDA), which covers the greater Toronto market area. The start of delivery for both deals is November 2012, which aligns with the in-service date for Statoil's Northern Access transportation capacity.

Azerbaijan

Statoil has a 25.5% share in the Shah Deniz gas/condensate field in Azerbaijan and is the commercial operator for gas transportation and sales activities for Shah Deniz stage 1 gas volumes. In addition, Statoil participates in the gas export negotiation committee for the Shah Deniz 2 project, which is led by the Azerbaijani state oil company SOCAR. Azerbaijan, Georgia and Turkey are part of the gas sales portfolio for stage 1 in which Turkey is the main market. Gas is purchased and sold through the Statoil-operated Azerbaijan Gas Supply Company (AGSC), and the gas is shipped to customers through the South Caucasus Pipeline (SCP), which runs from the Sangachal terminal in Azerbaijan via Georgia to the Georgian/Turkish border. Shah Deniz stage 1 gas transportation and sales reached 6.3 bcm in 2011, 3.7 bcm of which reached Turkey.

The stage 2 development of Shah Deniz is currently in the late stages of the concept selection phase of operator BP's capital value process. Field reserves support stage 2 production. In October 2011, the governments of Turkey and Azerbaijan signed an intergovernmental agreement relating to the sale of gas to Turkey and transportation through Turkey to the European markets. On the same date, the Shah Deniz Consortium entered into a gas sales agreement for 6 bcm per year and a transit agreement for 10 bcm per year with Botas in Turkey. Together with key partners in Shah Deniz, Statoil is currently negotiating sales contracts with several marketing companies in Europe and assessing alternative routes for bringing the gas into Europe.

Algeria

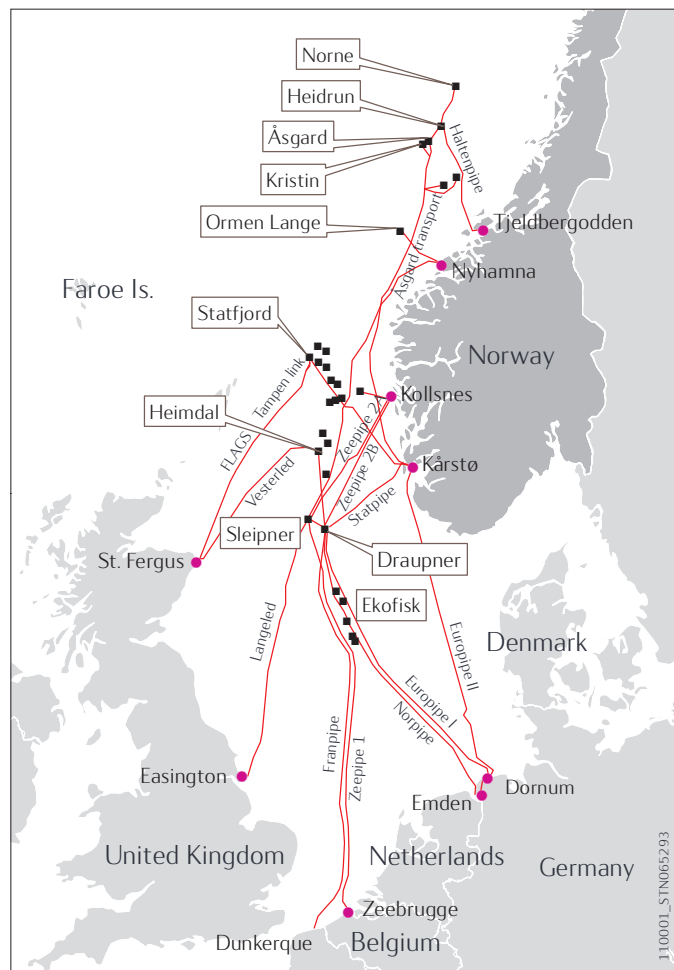
Statoil has a 31.85% share in In Salah and a 50% share in In Amenas, Algeria's third-largest and fourth-largest gas developments, respectively. All of the gas produced from In Salah is sold under long-term contracts.

LNG

The LNG production plant at Melkøya, the first and only large-scale LNG production facility in Europe, underwent technical maintenance from the end of April to the middle of July in 2011. The main scope was the replacement of a sea water cooler and the replacement of two electrical motors in the main compressors. LNG production has been more regular since the maintenance, and the facility's production is currently stable at design capacity. Market demand for LNG has been robust in 2011. Due to continued low prices in the USA, only a minimum number of cargoes, based on operational necessity, have been delivered to the USA. The remaining LNG portfolio has been diverted away from the US market into higher-priced markets in Europe and Asia. Statoil will continue to pursue its ambition to grow a global LNG portfolio, including non-equity LNG supply and commitments.

3.3.3.4 Norway's gas transport system

Over the last 30 years, the Norwegian gas pipeline system has been developed into an integrated system connecting gas-producing fields 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. All gas pipelines on the NCS with 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, a company wholly owned by the Norwegian state. In 2011, the Gassled system transported 94.2 bcm (3.3 tcf) of gas to Europe.

Statoil's ownership interests in Gassled have been adjusted twice in 2011. With effect from 1 January 2011, Petoro's interests increased by approximately 7% and all other parties reduced their interests proportionally. Statoil's ownership was reduced to 29.1% from 1 January 2011. Similar adjustments were made to the ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA.

In June 2011, Statoil entered into an agreement for partial divestment of its ownership interest in Gassled from 29.1% to 5.0%. The divested interest of 24.1% has been purchased by the financial investment company Solveig Gas Norway AS. The transaction was approved by the government authorities in December 2011, and the divestment date was 30 December 2011. The divestment does 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.

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.

As an integrated pipeline network with high flexibility and regularity, we believe that the Norwegian gas pipeline system is an essential facility in terms of ensuring reliable supplies of natural gas to Europe.

The tables below present facts about the NCS gas pipelines, including transportation routes and daily capacities, and about our ownership in Gassled and receiving terminals.

Gas pipelines included in Gassled	Start up date	Product	Start point	End point	Transport capacity ⁽¹⁾ mmcm/day	Statoil share in %
Zeepipe						
Zeepipe 1	1993	Dry gas	Sleipner riser platform	Zeebrugge	40.9	See Ownership structure Gassled
Zeepipe 2A	1996	Dry gas	Kollsnes	Sleipner riser platform	72.0	
Zeepipe 2B	1997	Dry gas	Kollsnes	Draupner E	71.0	
Europipe 1	1995	Dry gas	Draupner E	Dornum/Emden	44.5	
Franpipe	1998	Dry gas	Draupner E	Dunkerque	52.4	
Europipe II	1999	Dry gas	Kårstø	Dornum	64.6	
Norpipe AS	1977	Dry gas	Norpipe Y (Ekofisk Area)	Emden	43.1	
Åsgard Transport	2000	Rich gas	Åsgard	Kårstø	70.4	See Ownership structure Gassled
Statpipe						
Zone 1	1985	Rich gas	Statfjord	Kårstø	26.8	
Zone 4A	1985	Dry gas	Heimdal	Draupner S	33.3	
			Kårstø	Draupner S	20.1	
Zone 4B	1985	Dry gas	Draupner S	Norpipe Y (Ekofisk Area)	30.0	
Oseberg Gas Transport	2000	Dry gas	Oseberg	Heimdal	39.9	See Ownership structure Gassled
Vesterled (Frigg transport)	2001	Dry gas	Heimdal	St. Fergus	36.0	
Langed North	2007	Dry gas	Nyhamna	Sleipner Riser	Approx. 70.0	
Langed South	2006	Dry gas	Sleipner	Easington	68.0	
Tampen Link	2007	Rich gas	Statfjord	FLAGS	26.5 ⁽²⁾	
Norne Gas Transportation System	2001	Rich gas	Norne field	Åsgard Transport	11.0	
Kvitebjørn gas pipeline	2004	Rich gas	Kvitebjørn	Kollsnes	25.4	
Gjøa Gas Pipe	2010	Rich gas	Gjøa Field	FLAGS	17.0	

⁽¹⁾ We use committable capacity as a measurement for transport capacity. Committable capacity is defined as the capacity available for stable deliveries.

⁽²⁾ 26.5 mmcm/d is the maximal committable capacity.

Gas pipelines not included in Gassled	Start-up date	Product	Start point	End point	Transport capacity mmcm/day	Statoil share in %
Haltenpipe	1996	Rich gas	Heidrun field	Tjeldbergodden/ Åsgard Transport	7.1	19.06
Heidrun gas export	2001	Rich gas	Heidrun	Åsgard Transport	10.9	12.41

Terminal facilities included in Gassled	Startup date	Product	Location
Europipe Receiving Facilities	1995	Dry gas	Dornum, Germany
Europipe Metering Station	1995	Dry gas	Emden, Germany
Norsea Gas Terminal	1977	Dry gas	Emden, Germany
Kårstø Gas Processing Plant	1985	Dry gas/NGL	Kårstø, Norway
Easington Receiving Facilities	2006	Dry gas	Easington, UK
St.Fergus Terminal	1978	Dry gas	St. Fergus, Scotland
Kollsnes Gas Processing Plant	1996	Dry gas/NGL	Kollsnes, Øygarden Norway

Terminals not included in Gassled	Startup date	Product	Location
Zeepipe terminal JV ⁽¹⁾	1993	Dry gas	Zeebrugge, Belgium
Dunkerque terminal DA ⁽²⁾	1998	Dry gas	Dunkerque, France

⁽¹⁾ Gassled owners hold 49 per cent interest in the terminal.

⁽²⁾ Gassled owners hold 65 per cent interest in the terminal.

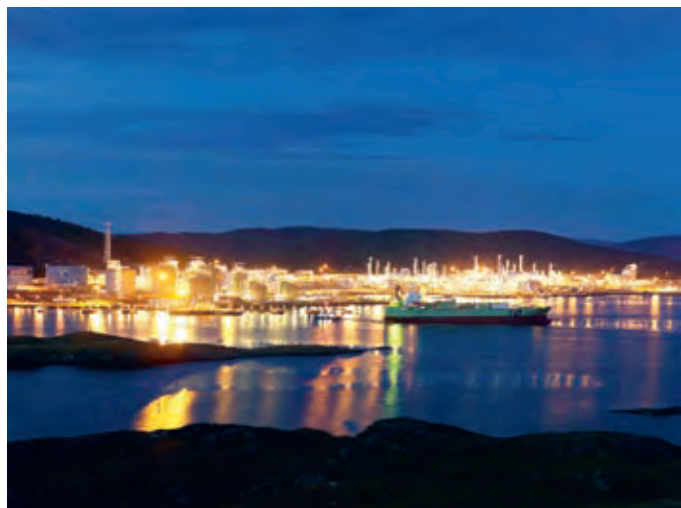
Ownership structure Gassled	Period 2009-2010	Period 2011-2028
Petoro AS ⁽¹⁾	38.43%	45.79%
Statoil ASA ⁽²⁾	32.07%	5.00%
ExxonMobil	9.40%	-
Total	7.76%	-
Shell	5.34%	-
Norsea Gas AS	2.72%	2.26%
ConocoPhillips	1.99%	1.68%
Eni	1.52%	1.28%
Dong	0.66%	0.98%
GDF SUEZ	0.09%	0.30%
RWE Dea	0.02%	0.08%
Njord Gas Infrastructure AS	-	8.04%
Solveig Gas Norway AS	-	23.48%
Silex Gas Norway AS	-	6.10%
Infragas Norge AS	-	5.01%

⁽¹⁾ Petoro holds the participating interest on behalf of the SDFI.

⁽²⁾ Changes in ownership in 2011: The divestment date for the transaction was 30 December 2011, and the net operating income in 2011 includes the operating results from the sold 24.1% interest.

3.3.3.5 Kårstø gas processing plant

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



Kårstø. Kårstø is currently preparing for the future with the ongoing KEP.

Kårstø processes rich gas and condensate (light oil) from the NCS received via the Statpipe pipeline, the Åsgard Transport pipeline and the Sleipner condensate pipeline. The processing plant currently has a rich gas capacity of 88 MSm³/d. Products produced at Kårstø include ethane, propane, isobutane, normal butane, naphtha and stabilised condensate. When all of these products have been separated from the rich gas, the remaining gas (dry gas) is sent to customers via the Statpipe, Europipe II and Rogass pipelines. The processing plant currently has a dry gas export capacity of 77 MSm³/d.

Since 2008, 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 the project name for several projects aimed at making the Kårstø facilities more robust and ensuring safe and efficient operation. The project investment is estimated to be around NOK 6 billion. The plan is to complete the remaining sub-projects in 2012.

3.3.3.6 Kollsnes gas processing plant

As technical service provider, Statoil is responsible for the operation, maintenance and further development of the Kollsnes gas processing plant on behalf of the operator Gassco.



Kollsnes. At Kollsnes gas comes ashore for further processing before it is transported in pipelines to customers in Europe

The Kollsnes plant was initially built in 1996 to receive gas from the Troll field in two 36-inch pipelines. The treatment process at Kollsnes involves separating out the NGL, and compressing the dry gas for export via Statpipe, Zeepipe, Europipe I and Franpipe. The processing capacity at Kollsnes has increased several times since the facility became operational. In 2010, the Kollsnes projects (KOP) started with the aim of maintaining the high regularity of the plant. In addition, a third 36-inch pipeline from the Troll field to Kollsnes was installed. Kollsnes also receives gas from the Visund, Kvitebjørn and Fram fields. These volumes are processed through the NGL plant. The Kollsnes gas processing plant currently has a design capacity of 143 MSm³/day.

The Troll field is a swing producer based on customer off-take. During the year, monthly off-take generally varies between 25% and 100%.

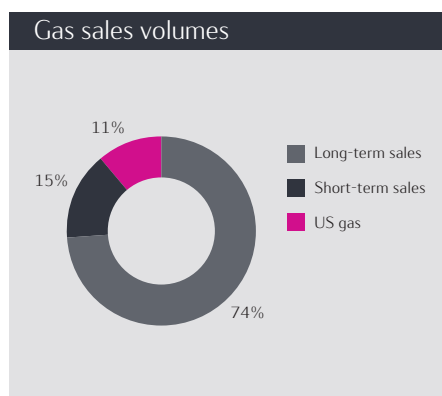
3.3.3.7 Gas sales agreements

Statoil manages, transports and markets approximately 80% of all NCS gas and has a growing US gas position. In Europe, the gas is sold through long-term contracts with major European utilities, and a growing proportion is direct sales.

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

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

The long-term contracts contain flexibility arrangements guaranteeing a minimum annual off-take - the so-called take-or-pay quantity - and they provide daily flexibility for the customer. Prices in traditional long-term contracts are generally tied to a formula based on the prices for substitute fuels for natural gas, typically heavy fuel oil and gas oil. In our gas portfolio, we also have gas sales contracts that are priced with reference to a gas spot market index. There can be significant price fluctuations during the life of the contract. Most of the traditional long-term gas contracts contain contractual price adjustment mechanisms that can be triggered by the buyer or seller at regular intervals, or under certain given circumstances. In the last two years, the outcome of such discussions for values covered by long-term sales contracts has generally been the introduction of a small proportion of spot price indexation and/or limited reduction in the volume obligation for the buyer, and increased access to the continental spot markets for Statoil.

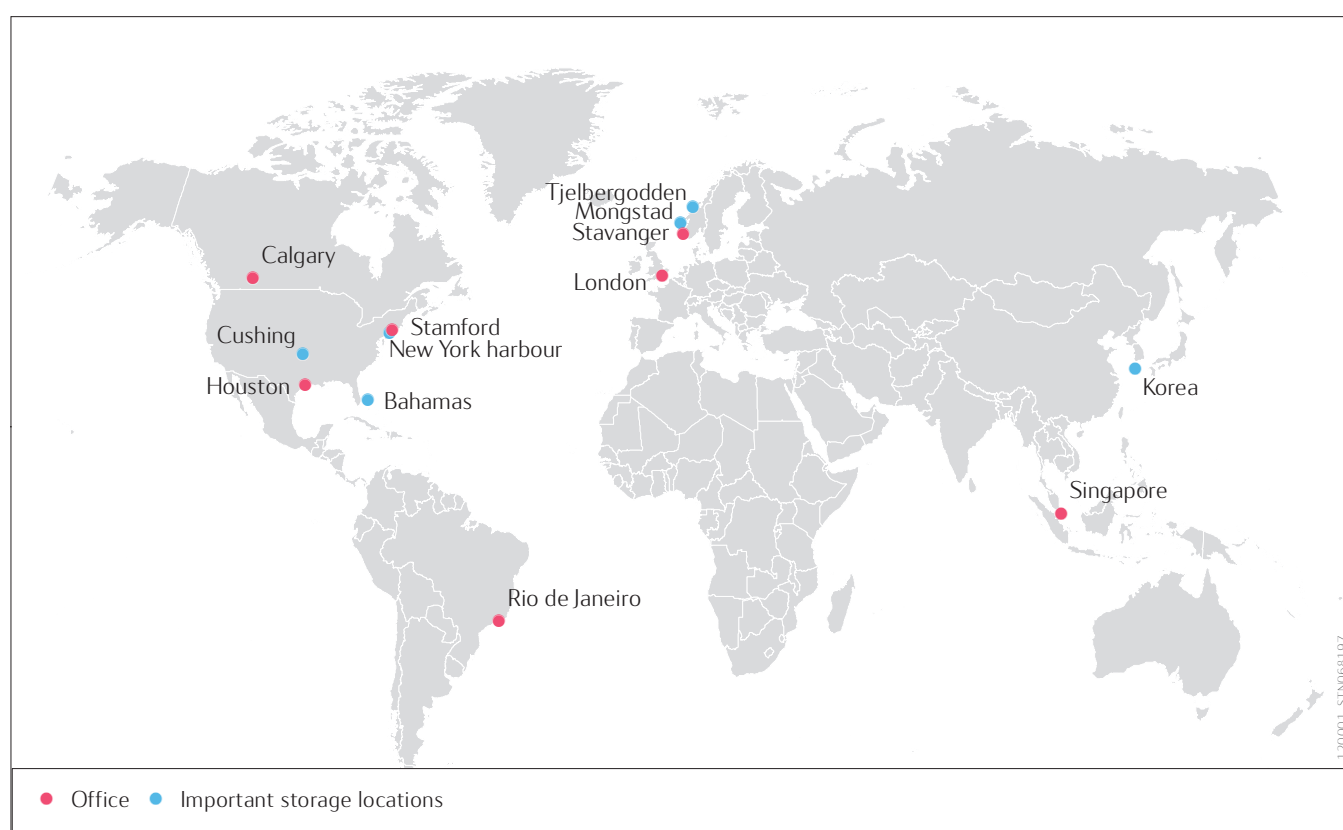


Statoil expects to continue to optimise the market value of the gas delivered to Europe through a mix of long-term contracts and short-term marketing and trading opportunities. This is done both as a response to customer needs and in order to capture new business opportunities as the markets become more liberalised.

3.3.4 Crude oil, liquids and products

3.3.4.1 Crude oil, liquids and products

Crude oil, liquids and products (CLP) 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. We are responsible for the commercial operation of two refineries (Mongstad, Norway and Kalundborg, Denmark) and the commercial operation of two crude oil terminals (Mongstad, Norway and South Riding Point, Bahamas). Our international trading activities make us one of the world's largest net crude oil sellers.

In 2011, MPR sold 671 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).

3.3.4.2 The oil market

The year 2011 had strong prices for Brent crude and significant volatility. The supply disruptions caused by the political turmoil in North Africa and the Middle East were important factors. The market for physical crude was tight and in backwardation.

The 2011 price for Brent crude averaged USD 111 per barrel, more than USD 30 higher than in 2010, and also significantly higher than the USD 97 per barrel from the previous record year of 2008. After starting 2011 at around USD 95 per barrel, Brent reached highs above USD 125 per barrel in April, and thereafter oscillated between USD 100 and USD 120 per barrel.

There are two main reasons why prices were strong in 2011. In 2010, oil demand growth came in at a record-high level of 2.9 mboe per day, as world demand rebounded quickly from the 2008-2009 recession, led by strong growth in non-OECD countries. This tightened global oil inventories sharply during the fourth quarter of 2010 and the first quarter of 2011, and we entered 2011 without much of the excess capacity that had formed in the oil market during the financial crisis of 2008-2009.

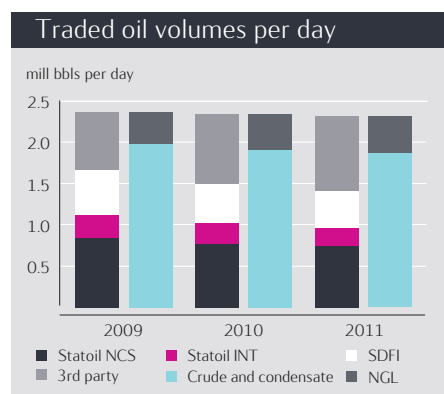
The "Arab spring" raised the general level of uncertainty attached to oil supplies from this region, and the outbreak of the Libyan civil war in February took 1.5 mboe per day of light sweet crude off the market. In addition, a string of production disruptions in some key producing countries wiped out much of the anticipated oil supply growth. Saudi Arabia and other key Persian Gulf member states responded by raising oil production, but not by enough to cover the entire loss of Libyan volumes. As a consequence, global oil inventories were reduced further. By late summer, they were near five-year lows, but increased slightly during the fourth quarter of 2011 compared to five-year lows.

As crude supply has lagged behind demand throughout 2011, the market for physical crude has been very tight. The market has been in backwardation throughout the year. The loss of Libyan crude exports as well as the many minor disruptions in North Sea production also led to strong premiums for North Sea light sweet crudes, and for Brent versus other global markers. In the USA, a lack of infrastructure to bring the rapidly increasing volumes of shale oil produced in the Midwest region to market led to sharp discounts for the inland WTI crude marker, which at some points traded as much as USD 25 per barrel below Brent crude. This dislocation has eased after the announcement that a key pipeline will be reversed to enable crude flows south to the US Gulf Coast. However, rapid changes in US inland oil balances will continue to cause turbulence on the North American crude market.

Increasing worries about the state of the global economy and about the sovereign debt situation in Europe and the USA capped the rally in crude prices and have led to significant volatility over the course of the year. However, due to the tight fundamentals in the oil market, crude has remained strong despite the increasing economic and financial headwinds. The nuclear disaster in Fukushima in Japan in March had a mixed effect on markets and added to volatility, but, over time, it has led to additional oil demand for power generation after most nuclear plants were taken off the grid for security checks.

3.3.4.3 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 selling and trading crude oil, condensate, NGL and refined products.



We market Statoil's own volumes and the SDFI's equity production of crude oil and NGL, in addition to third-party volumes. In 2011, our total sales of crude and condensate were equivalent to 671 million barrels, including supplies to our own refineries. The main crude oil market for Statoil is north-west Europe. In addition, we sell volumes 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 671 million barrels sold in 2011, approximately 41% were Statoil's own equity volumes.

The Product and Refinery Optimisation (PRO) unit is responsible for optimising and marketing Statoil's total production of 15 million tonnes of refined products from the refineries at Mongstad (Norway) and Kalundborg (Denmark). We also market the 865,000 tonnes of methanol from the Tjeldbergodden plant (Norway). In addition to equity volumes, we sell approximately 14 million tonnes of products in north-west Europe, the USA, and in the trans-Atlantic basin.

We are 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 LPG liftings at the Sture terminal.

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



3.3.4 Terminals

Statoil holds the lease for the South Riding Point crude oil terminal in the Bahamas until 2049, which includes oil storage as well as loading and unloading facilities. We also operate the Mongstad terminal and have shared ownership with Petoro.

South Riding Point

The terminal, which is located on Grand Bahama Island, consists of two shipping berths and ten storage tanks with storage capacity for 6.75 million barrels of crude. The overall occupancy was 10% in 2011 as the terminal was closed for upgrading in the first quarter and had limited operations during the second and third quarters. The total throughput in 2011 was approximately 25 million barrels.

In 2011, we upgraded the terminal to enable the blending of crude oils, including heavy oils. The blending is carried out onshore, and from ship to ship at the jetty.

This terminal is intended to both support our global trading ambitions and improve our handling capacity for heavy oils. We expect the new blending facilities and full terminal capacity to strengthen both our marketing and trading positions in the North American market. The terminal is also an important part of our plans to market our own volumes of heavy oil.

In addition to the existing lease period, we have an option to extend the agreement for an additional 30 years until 2079.

Mongstad terminal

Statoil operates the Mongstad terminal, which has storage capacity of 9.4 million barrels of crude. Statoil owns 65% of the terminal and Petoro the other 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 crudes and is an important tool in the marketing of North Sea crudes.

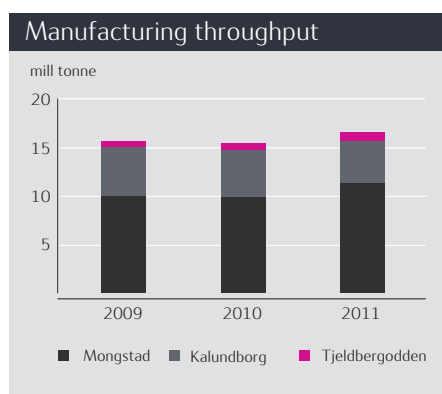
3.3.5 Processing and manufacturing

3.3.5.1 Processing and manufacturing

Processing and manufacturing is responsible for the safe, reliable and efficient operation of Statoil's onshore facilities.

This includes the refineries at Mongstad and Kalundborg, the methanol production plant at Tjeldbergodden and the gas processing plants at Kårstø and Kollsnes. It does not include the LNG plant at Melkøya, however. That plant is operated by DPN.

Processing and manufacturing is also responsible for the operation of the Oseberg Transportation System and the oil terminal at South Riding Point in the Bahamas.



We are the majority owner (79%) and operator of the Mongstad refinery in Norway, which has a crude oil and condensate distillation capacity of 220,000 barrels per day. We are 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. In addition, we have rights to 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. Our methanol operations consist of an 81.7% interest in the gas-based methanol plant at Tjeldbergodden, Norway, which has a design capacity of 0.95 million tonnes per year.

We also operate the Oseberg Transportation System (36.2% interest), including the Sture crude oil terminal. The terminal was built to receive crude from the Oseberg field by pipeline. Since 2003, it has also received crude from the Grane field pipeline. Oseberg blend (after stabilisation), Grane blend and some LPG are exported, while some LPG and naphtha is piped to Mongstad combined with condensate from the Kollsnes gas processing plant.

Processing and manufacturing performs the role of technical service provider (TSP) for the Kårstø and Kollsnes gas processing plants, in accordance with the technical service agreement between Statoil and the operator Gassco. Processing and manufacturing also performs the TSP role for Transport Net (Norway's gas transport system) and the oil terminal at South Riding Point, Bahamas. For further information on Kårstø, Kollsnes, Transport Net and South Riding Point, see Natural Gas and Crude oil, liquids and products, respectively above.

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

All data for year ended December 31 Refinery	Throughput ⁽¹⁾			Distillation capacity ⁽²⁾			On stream factor % ⁽³⁾			Utilization rate % ⁽⁴⁾		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
Mongstad	11.3	9.9	10.0	9.3	8.7	8.7	98.4	97.3	92.3	89.9	82.7	86.8
Kalundborg	4.4	4.8	5.0	5.4	5.5	5.5	93.24	97.2	95.3	95.9	86.6	88.2
Tjeldbergodden	0.86	0.8	0.71	0.95	0.95	0.95	97.2	95.0	82.6	97.3	96.9	90.2

⁽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 utilization rate for all processing units, stream day utilization.

Due to the challenging refining market, Statoil initiated a five-year programme to improve the competitive position of our onshore facilities through increased efficiency, reduced operating expenses and value creation. The improvement programme reached its yearly target for 2011.

3.3.5.2 Mongstad

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.



Mongstad

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. This makes Mongstad an attractive site for landing and processing hydrocarbons and for the further development of our oil and gas reserves. Statoil owns 79% of the refinery, while Shell owns the remaining 21%.

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.

Approximately 45% of Mongstad's total production is delivered to the Scandinavian market, while 55% is exported to north-west Europe and the USA. The following table shows the approximate quantities of refined products (in thousands of tonnes) produced at Mongstad for the periods indicated. In addition to crude, the Mongstad refinery upgrades large volumes of heavy fuel oil, NGL from Oseberg and Tune, and condensate from Troll, Kviteseid, Visund and Fram.

Mongstad product yields and feedstock	2011		For the year ended 31 December 2010		2009	
LPG	378	3%	360	4%	372	4%
Gasoline / naphtha	4,829	43%	4,258	43%	4,401	44%
Jet / kerosene	783	7%	681	7%	717	7%
Gasoil	4,234	37%	3,539	36%	3,473	34%
Fuel oil	183	2%	231	2%	374	4%
Coke / sulphur	228	2%	174	2%	164	2%
Fuel, flare & loss	684	6%	620	6%	532	5%
Total throughput	11,320	100%	9,863	100%	10,033	100%
Troll, Heidrun (FOB crude oils)	6,751	60%	4,516	46%	4,062	40%
Other North Sea crude oils (CIF crude oil)	1,777	16%	2,452	25%	3,679	37%
Other crude oils	274	2%				
Residue	1,278	11%	1,523	15%	1,316	13%
Other fuel and blendstock	1,239	11%	1,372	14%	976	10%
Total feedstock	11,320	100%	9,863	100%	10,033	100%

Note: Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnarounds in 2010).

The Mongstad refinery can manufacture products to meet different specifications through in-line blending during ship loading.

The refinery's reliability (on-stream factor) was high in 2010 and 2011, and we carried out a major turnaround in 2010. Capacity utilisation (the proportion of available plant capacity actually used) has been reduced depending on the market situation.

The new CHP plant started commercial operation on 20 December 2010, and it is part of a strategically important project. The plant improves the Mongstad refinery's energy efficiency and has a capacity of approximately 280 megawatts of electric power and 350 megawatts of process heat. The plant will have a gradual start-up phase as the refinery needs less steam due to a changed feedstock pattern, lower throughput and the postponement of projects. The plant is operated by Dong Energy, with Statoil paying an annual tariff for its use. In addition to the CHP plant, the CHP investment project included a new gas pipeline from Kollsnes and necessary modifications at the refinery.

In 2011, Statoil decided to continue its investment in the upgrade of its Coker plant (DCR project) to ensure a more effective process and improve working conditions.

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 *Renewable energy* section for further information.

3.3.5.3 Kalundborg

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.



Kalundborg

The refinery is connected via two pipelines (one gasoline and one gas oil) to our terminal at Hedehusene near Copenhagen, and most of our products are therefore sold locally.

Kalundborg's refined products are also supplied to other markets in north-west Europe, mainly Scandinavia.

The following table shows the approximate quantities of refined products (in thousand tonnes) produced by Kalundborg in the periods indicated.

Kalundborg product yields and feedstock	2011		For the year ended 31 December 2010		2009	
LPG	60	1%	80	2%	71	1%
Gasoline / naphtha	1,399	32%	1,461	31%	1,620	32%
Jet / kerosene	39	1%	141	3%	130	2%
Gasoil	1,980	46%	2,124	44%	2,140	43%
Fuel oil (2)	683	16%	756	16%	886	18%
Coke / sulphur	6	0%	7	0%	0	0%
Fuel, flare & loss	177	4%	186	4%	189	4%
Total throughput(1)	4,344	100%	4,755	100%	5,036	100%
Condensates: Ormen Lange, Snöhvit, Sleipner	594	14%	754	16%	998	20%
Other North Sea crude oils	2,854	66%	3,492	73%	3,713	74%
Other fuel and blendstocks	280	6%	234	5%	202	4%
Other crudes	617	14%	275	6%	123	2%
Total feedstocks	4,344	100%	4,755	100%	5,036	100%

Note: Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnarounds in 2010 and 2011).

The refinery's reliability (on-stream factor) was good in 2011 and on a par with its best years. The throughput in 2011 was lower due to a planned maintenance turnaround and the economic downturn. The product yield from the refinery is well positioned in relation to the expected future demand structure in the European market.

3.3.5.4 Tjeldbergodden

The methanol plant at Tjeldbergodden is the largest in Europe and one of the most energy efficient in the world. It is supplied with natural gas from the Heidrun field in the Norwegian Sea through the Haltenpipe pipeline.



Tjeldbergodden

Statoil owns 81.7% of the plant, which has a maximum proven capacity of 0.92 million metric tonnes per year (mmtpa). The actual throughput in 2011 was 0.86 mmtpa, compared to 0.80 mmtpa in 2010.

Statoil also owns 50.9% of Tjeldbergodden Luftgassfabrikk DA, one of the largest air separation units (ASU) in Scandinavia.

3.3.5.5 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 in which Statoil has a 36.2% interest.



Sture terminal

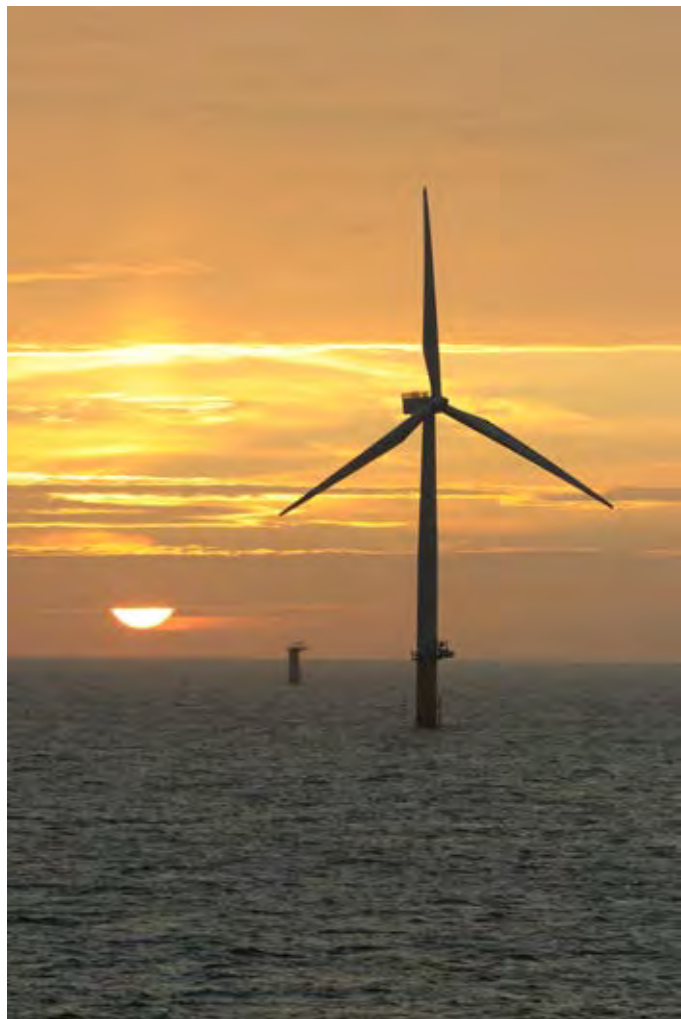
The terminal has a storage capacity of 6.3 million barrels of crude.

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.

The LPG processing capacity is a maximum 68 tonnes/hour. The import capacity is approximately 96,000 cm/d of Oseberg blend, and approximately 40,000 cm/d of Grane oil.

3.3.6 Renewable energy

Our renewable energy business focuses in particular on developing business in areas where we may have a competitive edge as a result of our offshore oil and gas expertise. Key areas are offshore wind and carbon capture and storage (CCS).



Sheringham Shoal

Sheringham Shoal

In partnership with the Norwegian utility company Statkraft, we are building one of the largest offshore wind farms in the UK off the Norfolk coast. The farm will cover more than 35 square kilometres and consist of 88 wind turbines that will be capable of producing enough energy for 220,000 UK homes. The site was chosen for its high wind speeds, shallow water depths, and location outside protected environmental areas. Electricity production from the wind farm commenced in August 2011.

Hywind

The Hywind demonstration facility off the coast of Karmøy - featuring the world's first full-scale floating offshore wind turbine - has been in operation for two years. The overall performance of Hywind has exceeded expectations, with the technology proving to be both robust and reliable. Projects have now been initiated to investigate the possibility of installing the Hywind test pilot scheme in both the USA and UK.

Full-scale carbon capture Mongstad (CCM)

The Norwegian government and Statoil are planning a full-scale carbon dioxide capture project in conjunction with the combined heat and power (CHP) station at Mongstad. At full capacity, the amount 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 uniqueness in relation to the technology involved. The project planning will have to reflect that the capture plant is to be integrated with the existing CHP and refinery in production. 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 expected in 2016.

3.4 Statoil Fuel & Retail (SFR)

SFR is a leading road transportation fuel retailer with a presence in eight countries across Scandinavia and central and eastern Europe. The group is also involved in the sale of stationary energy, marine fuel, aviation fuel, lubricants and chemicals.

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) on 22 October 2010. Statoil ASA is the majority shareholder in SFR, holding 54% of the shares. SFR's results are consolidated in Statoil ASA's financial statements.

3.4.1 Introduction to SFR

SFR is a leading Scandinavian road transportation fuel retailer with over 100 years of operations in the region. SFR has also established a strong presence in Poland, Latvia, Lithuania, Estonia and Russia.

As of 31 December 2011, SFR had a network of 2,305 fuel stations across its eight countries of operation, comprising a combination of full-service stations – which have integrated convenience stores – and automated fuel stations and truck stops. Of these, 1,739 fuel stations are located in Denmark, Norway and Sweden, and 566 are located in Poland, Latvia, Lithuania, Estonia and Russia.

In addition, SFR is involved in the sale of stationary energy (mainly heating oil, kerosene, LPG and heavy fuel for industrial purposes) and marine fuel (marine gas oil and heavy fuel) as well as aviation fuel, lubricants and chemicals.

3.4.2 SFR key events in 2011

Statoil Fuel & Retail recorded a strong financial performance in Scandinavia in 2011, but noted more challenging conditions in central and eastern Europe.

- Robust financial performance in Scandinavia, primarily driven by the strong execution of micro-market pricing of road transportation fuel, stringent cost control and effective cost-reduction measures.
- Challenging market conditions in central and eastern Europe, mainly due to the reluctance of major players in Poland and Russia to reflect higher levels of refined oil product prices in retail prices. This was partly offset by strong convenience sales and high operational cost-efficiency in the region.
- SFR's cost savings programme progressed ahead of schedule, generating savings of NOK 105 million in 2011, an increase of NOK 55 million compared with the initial target for 2011. The scope of the total cost savings programme, with an initial target of total savings of NOK 400 million by 2015, was increased in 2011 by NOK 50 million to NOK 450 million.
- Continued network expansion in 2011, adding 51 new stations in central and eastern Europe, and 12 new stations in Scandinavia.
- SFR also benefited from a positive development in convenience gross profits, despite a slight decline in like-for-like sales. The main contributors to the positive development have been successful innovation, strong brand development, high customer loyalty and strong loyalty programmes.
- Establishment of a real estate asset management strategy, focusing on improving the company's market position, creating value through real estate asset management optimisation and providing capital flexibility and efficiency.

3.4.3 The fuel and retail market

The retail road transportation fuel business primarily involves the sale of various gasoline fuels, diesel fuels, biofuels, and, in some markets, LPG for use in private and commercial vehicles, motorcycles and trucks.

These fuels are dispensed from pumps located at fuel stations that can either be manned, full-service stations that generally have an integrated convenience store, or self-service automated fuel stations with limited or no sales personnel on site and that do not have an integrated convenience store. In some markets, there is often an additional network of truck stops dedicated to the needs of commercial vehicles, which may be automated or part of full-service fuel stations, but which have dedicated lanes with high-speed pumps and other infrastructure to cater for large vehicles such as trucks.

The non-retail road transportation fuel business involves bulk sales of some or all of the road transportation fuels described above to industrial and commercial customers, such as car rental fleets, road construction crews, bus services and factories, and to independent resellers or retailers. Non-retail road transportation fuel sales frequently involve delivering fuel directly to the end-user's own in-house fuel storage facilities, although a number of SFR's wholesale customers also purchase products directly from the company's terminals and depots using their own transportation systems.

With respect to customers, road transportation fuel is sold to both customers purchasing road transportation fuel in their individual capacity for personal use ("B2C") and to business or commercial customers purchasing road transportation fuel in connection with their work or profession ("B2B").

In addition to the sale of road transportation fuel, the retail road transportation fuel business also involves sales of a broad range of convenience products and services from convenience stores that are an integrated part of full-service fuel stations. The range of convenience products and services provided at fuel station convenience stores includes candy, snacks, drinks, and tobacco. It can also include a wider range of products, such as fast food and vehicle-related products, as well as the provision of certain vehicle-related services, such as air/water, car wash and car rental. The range of fuel station convenience products and services varies between fuel station operators and occasionally between different fuel stations with the same operator. Some fuel station operators focus mainly on car accessories and car-related products and services, while others focus more on food-related products, such as fast food, coffee, baked goods and beverages.

3.5 Technology, Projects and Drilling (TPD)

3.5.1 Introduction to TPD

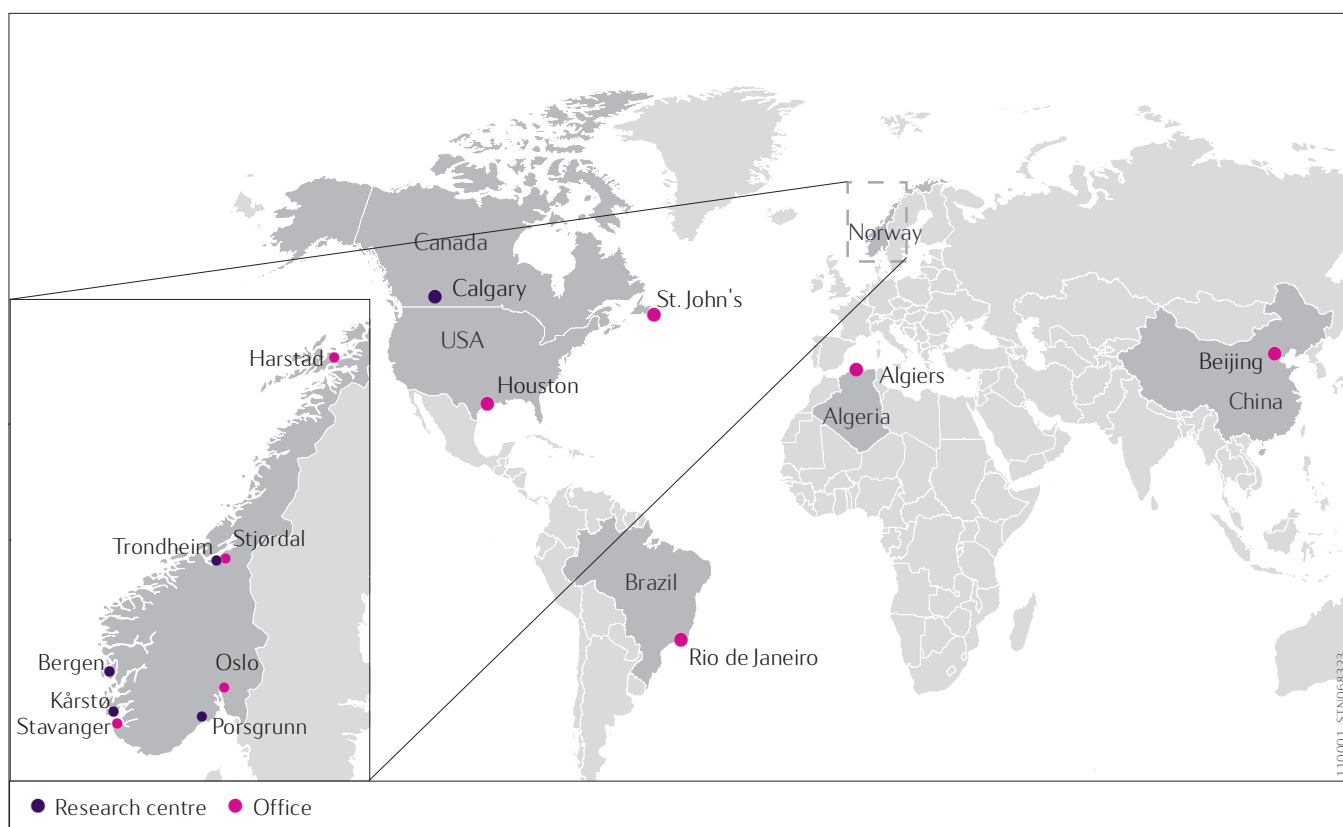
Technology, Projects and Drilling (TPD) is an internal function that is responsible, as a global service provider to Statoil, for delivering projects and wells and for providing support through global expertise, standards and procurement.

TPD business priorities:

- Safe and cost-effective project and wells
- Contribute to delivering production
- Add value from technology implementation
- Drive standardisation and simplification
- Ensure expertise and capacity

TPD is also responsible for promoting Statoil as a technology group, including developing and implementing new technological solutions.

Statoil has revised its corporate technology strategy, which sets the strategic direction for how technology development and implementation can address the challenges and contribute to achieving the corporate ambitions for 2020 and beyond.



3.5.2 TPD key events in 2011

In 2011, TPD delivered innovation, technology implementation, procurement strategies, project execution, safe and efficient drilling, and well operations.

- In August 2011, Statoil decided to implement subsea gas compression on the Åsgard field in 2015 - the first project of this kind in the world.
- The Peregrino field's (Brazil) first development phase included two drilling and wellhead platforms, and a ship-shaped floating production, storage and off-take unit was delivered to production. Using well-known technology, adapted and combined in an innovative way, has made it possible to start producing from Statoil's largest heavy crude oil field.
- The steel support structure for the Gudrun platform is now in place on the North Sea field, completing the first phase of the extensive installation work being carried out there.
- Statoil has issued an invitation to tender for a new type of drilling rig (cat D) specially designed for use on mature fields on the Norwegian continental shelf (NCS).
- The revised corporate technology strategy sets the strategic direction for technology development and implementation.
- New research and development offices opened in Rio de Janeiro (Brazil), Houston (USA) and St. John's (Canada).

3.5.3 Research and development

The research and development (R&D) business cluster is responsible for carrying out research to meet Statoil's business needs.

A world-class research and development organisation is crucial in order to support Statoil's growth ambition and to solve complex technology challenges on the NCS and internationally.

Statoil's R&D portfolio is organised in seven programmes covering the main upstream building blocks where Statoil is growing. The R&D organisation operates and further develops laboratories and large-scale test facilities and has an academia programme that addresses cooperation with universities and research institutes.

R&D expenditure has been approximately NOK 2.1 billion per year for the last three years. Cooperation with external partners such as academic institutions, R&D institutes and suppliers is crucial in relation to technology.

Statoil has four research centres in Norway, a heavy oil technology centre in Canada and an R&D office in Beijing (China). In addition, we have expanded our R&D activities with offices in Rio de Janeiro (Brazil), Houston (USA) and St. John's (Canada), close to many of our international operations.

Exploration

Our exploration research focuses on three key business challenges: (i) securing exploration growth and resource replacement, (ii) early access to frontier basins and plays, and (iii) exploration and exploitation of unconventional resources such as shale gas and oil and gas hydrates.

Increased recovery

For proved reservoirs, the aim is to optimise hydrocarbon recovery by improving ways of identifying remaining resources and efficiently draining our reservoirs. The business potential of technologies that address increased recovery is significant. We focus specifically on the challenge of resource and reserve replacement. Moving the barrels faster from resources to production and maintaining current production levels requires a combination of innovative technologies and simple, but smart solutions. We are addressing resource and reserve replacement, contributing to next-generation reservoir exploitation and looking for ways in which we can implement fast-track processes for a broader range of projects.

New development solutions

Innovative cost-efficient offshore field development solutions are resulting in a transition from topside facilities to intelligent, remotely-operated, autonomous seabed facilities, coupled with ultra-long, subsea tie-backs and well stream compression devices. However, we also see that compact processing technology developed for subsea application has a substantial potential to improve production efficiency on existing topside facilities. The aim is to improve the regularity and performance of both new and producing fields. It is also necessary to increase our knowledge about design and operations in ice-bound areas and in ultra-deepwater conditions. We are developing technology for the processing and transportation of offshore heavy oil.

Oil and gas value chain

Statoil aims to develop competitive and sustainable technologies and expertise for use in the development of oil and gas value chains. The oil and gas industry is looking for solutions for the development of increasingly challenging hydrocarbon resources, and we are focusing on identifying and developing future unconventional hydrocarbon value chains. Challenging crude oils and acid gas removal are being addressed, and we continue to develop technologies to support Statoil's oil refineries, gas conversion and gas processing facilities.

New energy and HSE

Our commitment to environmental stewardship is twofold: firstly, meeting our objective of zero harm to the environment by expanding our toolkit of environmental monitoring and integrated risk-modelling systems, and, secondly, creating business in new energy sources. Our research into new forms of energy is focused on offshore wind and second-generation biofuels based on marine feedstock. Cost and energy-efficient carbon capture and storage (CCS) that does not harm the environment is an important technology being addressed by Statoil.

Heavy Oil Technology Centre

Our extra-heavy oil research is aimed at developing technologies that increase the reserve base and result in more cost-efficient and environmentally sustainable production of extra-heavy oil. Extra-heavy oil research has been a top priority this year. The Heavy Oil Technology Centre (HOTC) programme has been established to strengthen our efforts in heavy oil technologies. A key focus of the centre, which draws on the expertise of the whole Statoil group, is the development of new technologies that will result in lower greenhouse gas emissions and a reduced environmental footprint. Statoil has launched a technology plan to help reduce carbon emissions from oil sands. The stated ambition is to reduce emissions significantly by 2025.

Gulf of Mexico and Brazil

Statoil has established an R&D programme to ensure focus on enabling technologies for realising business opportunities in deep water in the Gulf of Mexico and Brazil. The aim is to improve our mapping and evaluation of low permeable reservoirs, deepwater drilling and future field development solutions in order to cut costs and improve recovery, with particular focus on deep Palaeogene reservoirs. Cross-disciplinary groups have also initiated intensive research on the application of advanced geological interpretation, well technology and improved recovery methods.

Academia

As part of our research efforts, we are engaged in an extensive collaboration programme with academic institutions in which we gain access to world-class research in strategic areas for Statoil. By stimulating the development of leading expertise in the energy segment, we also secure long-term recruitment to science and technology.

By supporting collaboration between universities, research institutions and industry, we also contribute to building a strong Norwegian petroleum cluster. Through the R&D programmes and our international offices, we also cooperate with international universities and organisations in countries such as Canada, the USA, China and Brazil.

Selected technology advances and important milestones 2011:

Heavy Oil Technology Centre

Solvent co-injection was approved in the Kai Kos Dehseh (KKD) oil sands project in Canada. The facilities are under construction and the first solvent is expected to be co-injected with steam by 1 December 2012.

Exploration

The advanced imaging algorithm reverse time migration (RTM) has provided superior images and very fast turnaround in complex geological settings such as sub-salt compared with external technologies.

New energy and HSE

A contract has been signed to develop the world's first integrated environmental monitoring system (IEM) for oil and gas activities. Start-up is planned for 2012.

New development solution, and lab and test facilities

The multi-phase flow loop in Porsgrunn, Norway, was completed in early 2011. It is capable of testing oil and water in two-phase pumping, separation and degassing. Testing with heavy oil from Grane and Mariner was carried out during the summer and autumn of 2011 and is planned to continue in the future with Peregrino oil.

3.5.4 Technology excellence

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

TEX is a leader in the application of new technology in Statoil and in the oil and gas industry. Our 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 2011:

Subsea gas compression - a technological quantum leap

In August 2011, Statoil decided to implement Åsgard subsea gas compression in 2015 - the first project of this kind in the world. With this innovative technology in place, the recovery rate and lifetime of several gas fields can be considerably increased, taking us one step closer to realising our goal of a total subsea factory. Processing on the seabed - and gas compression in particular - is an important technological advance in relation to developing fields in deep waters in vulnerable areas. Statoil is also running a wet gas compression project on Gullfaks and participating in Ormen Lange in close cooperation with Shell.

Hot-tap gives flexibility

Statoil is responsible for the development of new technology that makes it possible to tie in to a pipe on the seabed while it is in operation, without divers and without preparing the pipe for it. Operations can also take place at greater depths than before, which potentially could save Statoil and partners billions of NOK. Hot-tapping pipes in full operation at depths of up to 2,000 metres (via remote operation from a ship) could revolutionise the utilisation of the subsea network on the Norwegian continental shelf. The technology is developed by Statoil and can be significant to the development of marginal discoveries.

Fast track: moving from tailor-made to ready-made

Our expertise from 25 years of technology development subsea has given us the field-proven technology, expertise and infrastructure required to enable the fast-track concept. Together with external suppliers, we have developed a subsea catalogue for developments on the NCS at depths of up to 500 metres. It defines both standardised subsea equipment and configurability - from "bare bones" to "high functionality" solutions. The fast-track concept increases the speed and reduces the cost of developing smaller fields.

New model for calculating NOx emissions

A new model for calculating NOx emissions from gas turbines has been developed by Statoil to ensure a more predictive NOx emission monitoring system. As of year-end 2011, the new NOx monitoring system, which has been developed in-house, has been implemented for 69 of 78 gas turbines in DPN. Twenty of the 23 offshore installations are now using the new tool, and the remaining installations are planned to be included during early 2012. Implementation of this technology has been highly cost efficient compared with solutions from suppliers.

Optimal gas turbine water wash

Introducing new guidelines for optimised water wash of gas turbines is expected to increase the availability and efficiency of Statoil's gas turbine fleet. Statoil has a total of 140 gas turbines in operation. Fouling in the compressor section of the gas turbines is the main contributor to performance deterioration. It is removed by water wash.

Improved technology on Snøhvit brings significant energy savings

Improved technology at the Snøhvit LNG plant has reduced power consumption by 10% (15MW). The energy savings mainly come from improvements of the cooling efficiency of the internals in the subcooler and a new robustified condenser with vapour belts. Technology selection and qualification have been carried out by experts from TEX and R&D.

Large cost reductions on Valemon and Gudrun

New requirements have recently been adopted for where to apply passive fire protection. These new requirements have resulted in large cost reductions compared with previous practice, and they have also reduced the risk of major accidents. Passive fire protection applied to process piping and separators has been the source for external corrosion underneath the insulation due to sea water ingress. The corrosion can result in hydrocarbon leaks and an increased risk of major accidents.

Improved oil recovery

Very high recovery factors have been achieved by water injection on the NCS, but waste volumes of oil are still left in the ground. These are either bypassed by the injected water or trapped in the rock flooded by water. Three different technologies designed to improve recovery by water injection have been successfully field-tested in 2011. Low-saline water has been injected in the Heidrun field, showing a significant reduction in the amount of trapped oil in the water-flooded regions, and two different chemical systems to improve the distribution of injected water have been field tested on Snorre and Gullfaks.

3.5.5 Projects

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

PRO aims to be world class in terms of project performance, delivering cost-efficient projects on time and in accordance with high HSE standards and agreed quality standards. To become a truly global energy player, Statoil must be capable of executing projects at the very highest level.

PRO will continue to emphasise competitive cost and quality in design and execution in order to improve performance and be fit to face the fiercer competition of tomorrow. Great efforts are made to set the direction of the key drivers in Statoil's projects in the early phase, when the possibility of influencing costs and value creation is greater.

Experience transfer from fast-track projects is the key, in particular in simplification and swift implementation of improvements. Fast-track projects are subsea tie-in projects in which standardised solutions are used to reduce the time from discovery to production from five to 2.5 years. Reducing costs by 30% is also an ambition for fast-track projects.

Important milestones 2011

The main events in PRO in 2011 included the start-up of Peregrino production and completion of the South Riding Point terminal upgrade, which is crucial in relation to the sale of the oil from the Peregrino field. The mega-projects Valemon and Gudrun continued to progress in 2011, and Åsgard subsea compression entered the execution phase. In addition, the following fast-track projects were sanctioned in 2011: Stjerne, Vigdis Northeast, Hyme, Vilje South, Skuld and Visund North.

Project development

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. We have also started on cessation projects on the NCS.

List of PRO's main deliveries:

Project completions 2011	Type
Offshore greenfield and wind	Peregrino
Onshore, cessation and pipelines	Kårstø double inlet crossover (Dixo), Snøhvit improvement project, South riding point terminal upgrade/pipeline modification, Kollsnes projects
Fast-track and subsea projects	Statfjord C riser replacement,
Offshore brownfield	Snorre A produced water, Snorre A improved oil recovery, Åsgard A new swivel, Gullfaks A cement unit, snorre A living quarter upgrade, Troll P12 pipeline, Statfjord late life
Expected project completions 2012 - 2013	Type
Offshore greenfield and wind	Sheringham shoal offshore windfarm
Onshore, cessation and pipelines	Kårstø NGL metering station, Technology centre (TCM), Kårstø expansion project (KEP 2010), Mongstad delayed coker revamp
Fast-track and subsea projects	Smørbukk Northeast, Åsgard gas transfer, Ormen Lange subsea compression pilot, Marulk, Visund South, Tordis Vigdis control module (TVCM), Tordis flowline replacement, Vigdis Norhteast, Skuld, Stjerne, Hyme, Visund North, Vilje South
Offshore brownfield	Åsgard B CO2 removal, Peregrino salt and sulphate removal, Troll A living quarter extension, Oseberg D heat recovery steam generator, Oseberg C drilling upgrade, Gullfaks B water injection unit, Kvitebjørn pre-compression, Oseberg B drilling upgrade

3.5.6 Drilling and well

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

D&W will seek to industrialise drilling operations by exploiting new technologies for intelligent and safe well construction. The goal is to increase cost-effective drilling and improve HSE. D&W will continue to target enhanced operational excellence, and the outlook going forward indicates strong activity, with the delivery of several new rigs and the takeover of Brigham, Eagle Ford and Marcellus. Exploiting new technology to increase efficiency and secure necessary resources will be a critical success factor.

The most important part of our operational excellence is safe drilling and well operations worldwide. We experienced a decreasing rate of serious HSE incidents, falling objects frequency and accidental spills. There were no serious well control incidents in 2011 (the last incident was in July 2010).

D&W has delivered 87 wells offshore, an increase of 36% since 2010. In addition, almost 33% of the wells were exploration wells - up from 11% in 2010. There were also 12 international exploration wells - including side tracks - in 2011, compared with zero in 2010. The number of rig years increased from 32 to 37 years. The figures reflect the positive effects of Statoil's simplified and cost-effective drilling strategy.

D&W's onshore activity delivered 125 exploration wells in Canada during the winter drilling programme.

Statoil has issued an invitation to tender for a new type of drilling rig specially designed for use on mature fields on the NCS. The rigs delivered to the NCS in recent years were primarily designed for operation in deep water. However, as many discoveries on the NCS have become smaller (with exceptions such as Aldous, Avaldsnes and Skrugard), it is becoming more important to increase drilling activity in mature fields in order to realise their full potential. The purpose is to make the drilling and completion of production wells cost efficient and safer, and to boost oil recovery.

3.5.7 Procurement

Procurement (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 is more than NOK 100 billion from approximately 12,000 active suppliers. They are procurements for projects, maintenance and operations, drilling and well, and business support. Our 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 therefore encourage and facilitate collaboration with our suppliers through communication and managing supplier relations. By maintaining strong relations with high-quality suppliers, Statoil aims to ensure lasting long-term competitive advantages. Our procurement approach and how we collaborate and work together with high-quality suppliers will be crucial in relation to enabling technology development and innovation.

PSR develops the supplier base through linking demand in Statoil with suppliers globally. The Asia-Pacific region has for the past few decades experienced staggering industrial development, and it now has a large number of suppliers to the oil and gas industry. China has led development in this region. It is the world's most expansive industrial nation, capable of delivering high quality on competitive terms. We believe that we will see many suppliers from this region becoming valuable to Statoil in the years to come, complementing our existing supplier base and securing capacity and quality.

Local content

We promote local deliveries and cooperate with local companies as contractors and suppliers where these are available, and we 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.

Ripple effects

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 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.

Statoil aims to make sustainable investments that benefit the communities and countries in which we operate. We do this by creating local content and generating positive spin-offs from our core business in support of development ambitions wherever we are present. We promote local sourcing and work with local businesses as suppliers and contractors where they exist. We invest in developing sustainable and competitive local enterprises. We support education and skills building in the local community and among our suppliers and contractors in order to build lasting capacity and to help them develop the skills standards and certifications required to work in the oil and gas industry.

Several rig initiatives

Securing rig capacity is crucial in relation to maintaining NCS production levels and increasing oil and gas recovery. To enhance recovery on the NCS and expand our international project portfolio, we will pursue new supply chain strategies and further increase our global supplier base. With the new category D rigs and our subsea fast-track portfolio, we have shown that we are flexible in pursuing new supply chain strategies to ensure fit-for-purpose solutions that meet our operational requirements. These units will be built in full compliance with the most recent applicable rules and regulations.

We have launched several initiatives:

Cat A - light well intervention vessels

Cat B - rig for heavy intervention and through tube drilling

Cat C - securing available conventional rig capacity

Cat D - specially designed mid-water rigs

Cat J - assessing the possibility of tendering for a large jack-up drilling rig

3.6 Global Strategy and Business Development (GSB)

3.6.1 Introduction to GSB

The ambition of the new Global Strategy and Business Development (GSB) organisation is to bring together Statoil's corporate strategy, business development, and merger and acquisition activities to actively drive growth and corporate development.

GSB was established as a new business area in 2011, with its main office in London. 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 renewed strategy, which was launched in June 2011, plays an important role in guiding Statoil's business development focus.

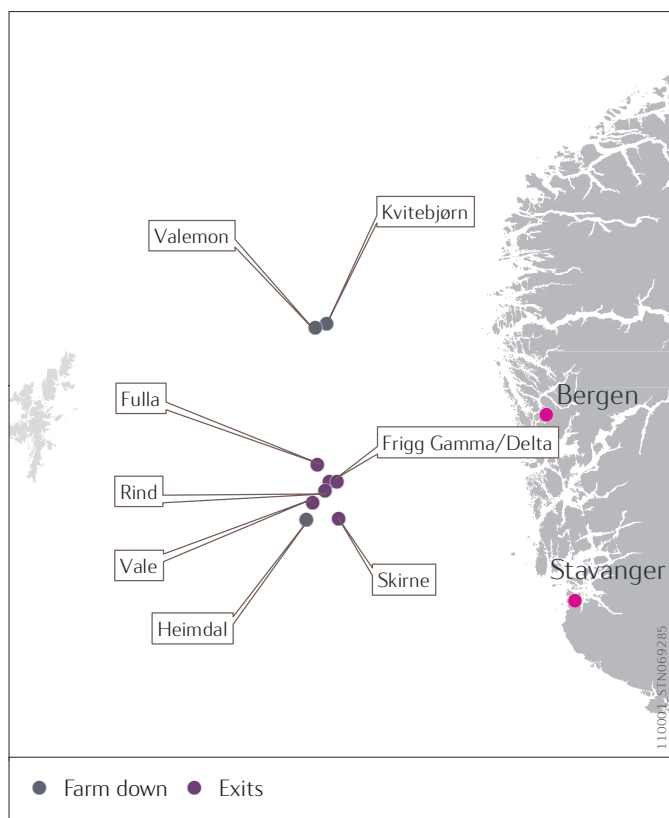
GSB's business activities are organised in the following areas:

- Corporate mergers and acquisitions: responsible for initiating and executing corporate mergers, acquisitions and divestment processes
- Corporate strategy and analysis: responsible for corporate strategy development processes, competitor intelligence, industry analysis and the running of Statoil's strategic advisory council
- New ventures: responsible for pursuing unconventional resource growth and new venture opportunities globally
- Business development execution: responsible for business development project execution, technical evaluation and commercial analysis.

GSB will spearhead inorganic moves towards Statoil's growth target as outlined in our renewed strategy.

3.6.2 GSB key events in 2011

GSB initiated, executed and concluded several large-scale business development projects in 2011 that reflect Statoil's strategic direction. Active portfolio management has realised substantial value and further strengthened Statoil's growth potential.

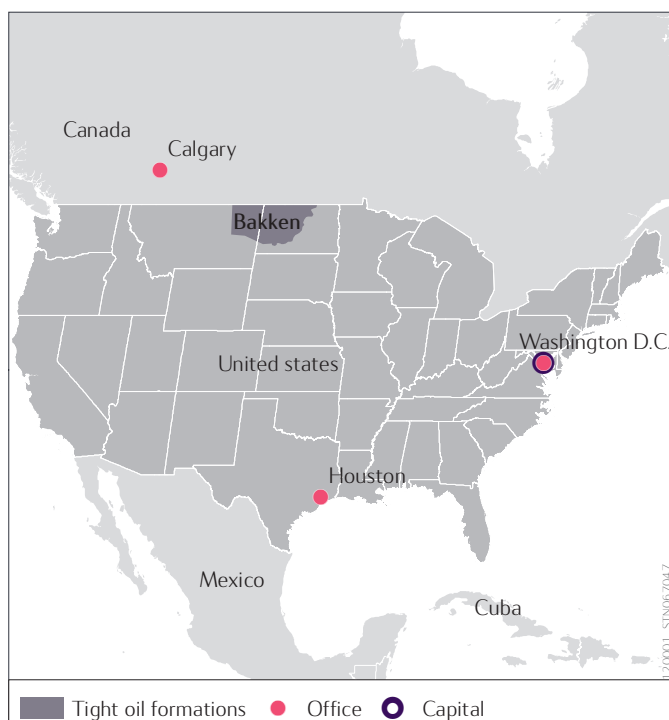


Below are the highlights from the past year:

- Statoil has further optimised its portfolio on the Norwegian continental shelf (NCS) by strengthening its position in growth areas through the acquisition of an additional interest in Snøhvit from Hess Norge. In parallel, the company has high graded parts of its portfolio by divesting interests and exiting less strategic fields.
- This high grading was principally carried out through a transaction with Centrica, a UK-based energy company and established NCS player. This deal, which is expected to close in 2012, involved Statoil farming down in three fields and exiting five. These assets were predominantly gas prone and represented about 130 million barrels net of recoverable oil equivalent. The transaction with Centrica entails a high valuation multiple that confirms the industrial value of Statoil's NCS gas business. This also strengthens Statoil's capacity to further focus on value-creating growth on the NCS, one of the world's most attractive oil and gas regions.
- Statoil's focus on reshaping the portfolio to fit the company's renewed strategic focus was further demonstrated by the decision to divest a 24.1% direct and indirect interest in the Gassled joint venture for NOK 17.35 billion in June 2011. The partial divestment of our interest in Gassled contributes to Statoil's flexibility in relation to re-deploying capital to assets and projects that yield more attractive rates of return. This is part of Statoil's continuous efforts to increase capital efficiency, drive shareholder value and secure future growth opportunities. Between 2009 and 2011, portfolio optimisation and divestment activity on the NCS, in Brazil and Canada, and the partial divestment of Statoil Fuel & Retail have generated more than USD 10 billion.
- In June 2011, Statoil and Talisman entered into an agreement with Denver-based independent SM Energy Company that added 15,400

acres to the companies' 50/50 Eagle Ford joint venture in Texas, USA for a total consideration of USD 225 million. Statoil plans to develop this area as an integral part of our overall plan for Eagle Ford.

In October 2011, Statoil and Brigham Exploration Company in the United States announced that they had entered into an agreement for Statoil to acquire all of the outstanding shares in Brigham for USD 36.50 per share through an all-cash tender offer. Subsequently, in December 2011, Statoil announced the successful completion of the tender offer, with more than 92.2 per cent of the outstanding shares of Brigham's common stock tendered. Statoil acquired all of the outstanding shares prior to year end. The total equity value of the acquisition was approximately USD 4.4 billion.



Brigham's principal business activity is centred around the development of the Bakken and Three Forks tight oil formations, which are considered to be among the largest oil accumulations in the United States. Statoil believes that such unconventional resource bases will be an increasingly important part of future energy supplies.

This acquisition builds on previous early entrance into the Marcellus and Eagle Ford plays, which has enabled Statoil to develop industrial shale capabilities. Entering the Bakken and Three Forks tight oil plays and taking on operatorship represents a further significant step for Statoil. It is in line with our renewed strategic direction set out during 2011. Statoil is committed to utilising its technological expertise, project execution skills and financial capability to secure continued high operational performance and value creation in these plays.

3.7 Significant subsidiaries

The following table shows significant subsidiaries owned directly by the parent company, as well as the parent company's equity interest and the subsidiaries' country of incorporation as of 31 December 2011.

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 Norsk LNG AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 17 AS	100	Norway	Statoil North America Inc.	100	United States
Statoil Angola Block 31 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Angola Block 38 AS	100	Norway	Statoil OTS AB	100	Sweden
Statoil Angola Block 39 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Angola Block 40 AS	100	Norway	Statoil Shah Deniz AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil Technology Invest AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil UK Ltd	100	United Kingdom
Statoil Danmark AS	100	Denmark	Statoil Venezuela AS	100	Norway
Statoil Deutschland GmbH	100	Germany	Statoil Venture AS	100	Norway
Statoil do Brasil Ltda	100	Brasil	Statpet Invest AS	100	Norway
Statoil Exploration Ireland Ltd.	100	Ireland	Statoil Methanol ANS	82	Norway
Statoil Forsikring AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Hassi Mouina AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil New Energy AS	100	Norway	Statoil Fuel and Retail ASA	54	Norway
Statoil Nigeria AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Nigeria Deep Water AS	100	Norway	Naturkraft AS	50	Norway
Statoil Nigeria Outer Shelf AS	100	Norway	Vestprosess DA	34	Norway

3.8 Production volumes and prices

Statoil's operational review accords with its segment's operations as of 31 December 2011, whereas certain disclosures about oil and gas reserves are based on geographical areas as required by the Securities and Exchange Commission (SEC).

For further information on extractive activities, refer to the sections *Operational review - Development and Production Norway* and *Operational review - Development and Production International*, respectively.

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

For further information about disclosures for oil and gas reserves and certain other supplemental disclosures based upon geographical areas as required by the SEC, refer to the section *Operational review - Proved oil and gas reserves*.

3.8.1 Entitlement production

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

The following table shows our Norwegian and international entitlement production of crude 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 an immaterial quantity of bitumen is included in crude oil production.

Entitlement production	2011	For the year ended 31 December 2010	2009
Norway			
Crude oil (mmbbls) ¹	252	256	279
Natural gas (bcf)	1,287	1,370	1,367
Natural gas (bcm)	36.5	38.8	38.7
Combined oil and gas (mmboe)	481	500	523
Eurasia excluding Norway			
Crude oil (mmbbls) ¹	15	18	19
Natural gas (bcf)	48	51	49
Natural gas (bcm)	1.4	1.4	1.4
Combined oil and gas (mmboe)	23	27	28
Africa			
Crude oil (mmbbls) ¹	46	53	63
Natural gas (bcf)	40	41	54
Natural gas (bcm)	1.1	1.2	1.5
Combined oil and gas (mmboe)	53	60	73
Americas			
Crude oil (mmbbls) ¹	31	26	20
Natural gas (bcf)	59	47	48
Natural gas (bcm)	1.7	1.3	1.4
Combined oil and gas (mmboe)	41	34	29
Total			
Crude oil (mmbbls) ¹	343	352	381
Natural gas (bcf)	1,434	1,509	1,519
Natural gas (bcm)	40.6	42.8	43.0
Combined oil and gas (mmboe)	598	621	652

1) Crude oil includes natural gas liquids (NGL), condensate and bitumen. NGL includes both LPG and naphta .

3.8.2 Production costs & sales prices

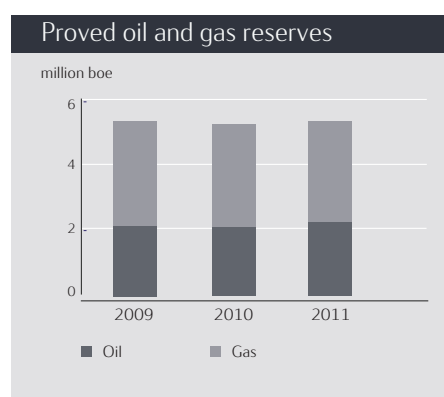
The following tables present the average unit of production cost based on entitlement volumes and realised sales prices.

	Norway	Eurasia excluding Norway	Africa	Americas
Year ended 31 December 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 Sm ³	2.2	1.0	1.9	0.9
Average production cost in NOK per boe	45.4	52.1	54.2	74.3
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 Sm ³	1.8	0.6	1.6	1.0
Average production cost in NOK per boe	40.6	42.0	49.3	66.2
Year ended 31 December 2009				
Average sales price liquids in USD per bbl	57.8	58.2	57.8	61.7
Average sales price natural gas in NOK per Sm ³	1.9	0.6	1.4	0.9
Average production cost in NOK per boe	36.9	55.2	40.9	45.3

3.9 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5,426 mmboe at year end 2011, compared with 5,325 mmboe at the end of 2010.

Statoil's proved reserves are estimated and presented in accordance with Securities and Exchange Commission (SEC) Rule 4-10 (a) of Regulation S-X, revised as of January 2009, and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins, as issued by the SEC staff. For additional information, see *Critical accounting judgements and key sources of estimation uncertainty*; *Key sources of estimation uncertainty*; *Proved oil and gas reserves* in note 2 *Significant accounting policies* to the consolidated financial statements. For further details on proved reserves, see also note 33 - *Supplementary oil and gas information* - to the consolidated financial statements.



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

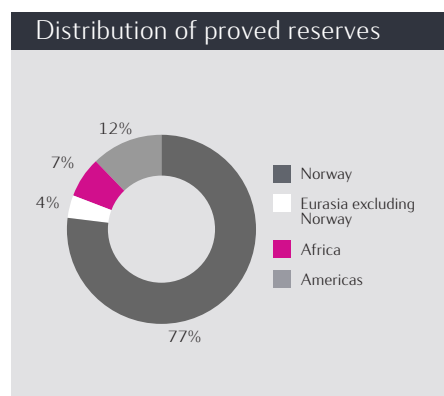
Proved reserves can also be added or subtracted through the acquisition or disposal of assets. Changes in proved reserves can also be due to factors outside management control, such as changes in oil and gas prices. While higher oil and gas prices normally allow more oil and gas to be recovered from 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 of 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, since 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 politically stable countries within the Organisation for Economic Co-operation and Development (OECD). Norway is by far the most important contributor in this category, followed by the United States of America (USA), Canada, Ireland and the United Kingdom (UK).



10% of our total proved reserves are related to production sharing contracts (PSCs) 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 and included in proved reserves in the Americas.

Significant additions to our proved reserves in 2011 were:

- The most important new contribution to our proved reserves was the acquisition of Brigham Exploration Company in late 2011, adding 122 million boe of purchased proved reserves.
- Added proved reserves related to approval of development plans for new field developments were mainly in Norway in 2011, where several new field development projects have been sanctioned. The main contributors are the Hild and Skuld fields. However, this category also includes the Hibernia South Extension development in Canada, which was sanctioned and started producing in 2011, and the Big Foot field in the USA.
- Further drilling in the Marcellus and Eagle Ford shale plays in the USA increased the proved reserves in 2011, and these additions are presented as extensions.
- Production experience, further drilling and improved recovery contributed positively to the revision of proved reserves in 2011, most significantly for several of our Norwegian fields in production, adding 364 million boe in total.

New discoveries with proved reserves booked in 2011 are all expected to start production within a period of five years.

More details relating to changes in proved reserves can be found under separate descriptions by geographical area below.

Summary of proved oil and gas reserves as of 31 December 2011

Reserves category	Oil and NGL (mmbbls)	Proved reserves Natural Gas (bcf)	Total oil and gas (mmboe)
Developed			
Norway	919	12,661	3,175
Eurasia excluding Norway	102	371	168
Africa	219	293	272
Americas	140	404	212
Total Developed proved reserves	1,381	13,730	3,827
Undeveloped			
Norway	450	3,027	990
Eurasia excluding Norway	11	237	54
Africa	93	138	118
Americas	340	548	438
Total Undeveloped proved reserves	894	3,951	1,599
Total proved reserves	2,276	17,681	5,426

Our proved reserves of bitumen in the Americas are included as oil in the table above as they represent less than 4% of our proved reserves, which is regarded as immaterial.

Basis for equivalents as 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 2011, 2010 and 2009.

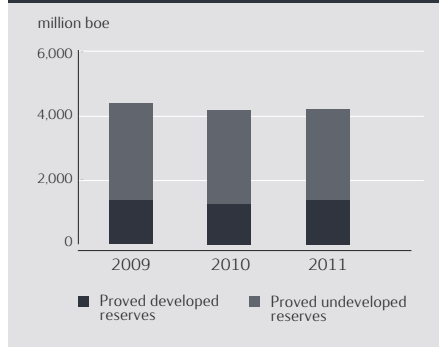
(million boe)	2011	For the year ended 31 December 2010	2009
Revisions and improved recovery	373	183	326
Extensions and discoveries	232	343	155
Purchase of petroleum-in-place	161	12	0
Sales of petroleum-in-place	(66)	0	(4)
Total reserve additions	700	538	476
Production	(598)	(621)	(652)
Net change in proved reserves	101	(84)	(176)

The reserves replacement ratio increased to 1.17 in 2011 from 0.87 in 2010. The increase in the reserves replacement ratio in 2011 is mainly due to large positive revisions, as well as the Brigham acquisition and increased ownership interests in the Norwegian fields Gudrun, Snøhvit and Valemon in 2011. The 2011 reserves replacement, excluding purchases and sales of petroleum in place, is 1.01. The average replacement ratio for the last three years was 0.92, including purchases and sales.

Reserves replacement ratio (including purchases and sales)	2011	For the year ended 31 December 2010	2009
Annual	1.17	0.87	0.73
Three-year-average	0.92	0.64	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.

Oil and gas reserves – Norway



Proved reserves in Norway

A total of 4,165 million boe is recognised as proved reserves in 63 fields and field development projects on the Norwegian continental shelf (NCS), representing 77% of our total proved reserves. Of these, 52 fields and field areas are currently in production, 45 of which are operated by Statoil. Several new field development projects sanctioned during 2011 are adding 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 2011. This includes decisions to invest in the upgrading of drilling facilities or installation of facilities for compression on fields such as Snorre, Njord and Åsgard.

Of the proved reserves on the NCS, 3,175 million boe or 76% are proved developed reserves. 67% of the total proved reserves are gas reserves, related to large offshore gas fields such as Troll, Ormen Lange, Snøhvit, Kvitebjørn, Oseberg, Visund and Tyrihans.

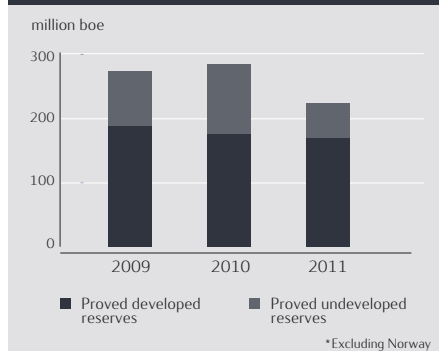
In the North Sea, five new field developments were sanctioned during 2011 and are carrying proved reserves for the first time: Hild, Stjerne, Svalin, Visund North and Vigdis North-East, all except Hild operated by Statoil. Increased equity interests in the ongoing field development projects Gudrun and Valemon added new proved reserves categorised as purchase of petroleum in place.

In the Norwegian Sea, development plans have been approved for the Hyme and Skuld projects, adding new proved reserves as extensions and discoveries.

In the Barents Sea, Statoil's ownership interest in the Snøhvit field has increased, adding new proved reserves categorised as purchase of petroleum in place.

The 2011 reserves replacement ratio for the NCS was 1.03, including purchases and sales.

Oil and gas reserves – Eurasia*



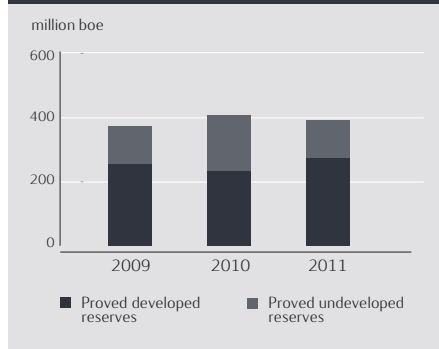
Proved reserves in Eurasia, excluding Norway

In this area we have proved reserves of 222 million boe related to six fields in the countries Azerbaijan, Russia, Ireland and the United Kingdom. Eurasia excluding Norway represents 4% 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. We do not carry proved reserves at year end 2011 related to our interest in the Jupiter field in the United Kingdom, as this is likely to permanently close down production in the near future.

An insignificant amount of reserves in Iran related to production entitlement following our previous activities in this country is included and no reserves related to Iraq are included.

Of the proved reserves in Eurasia, 168 million boe or 76% are proved developed reserves. 51% of the total proved reserves in this area are oil reserves and 49% are gas reserves.

Oil and gas reserves – Africa



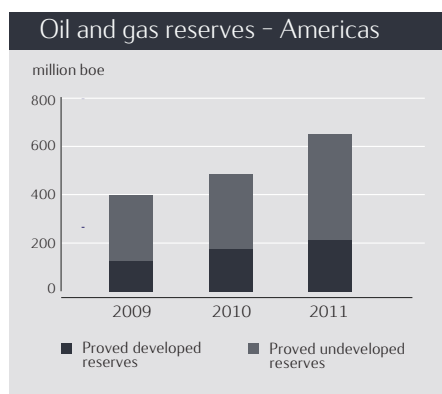
Proved reserves in Africa

We recognise proved reserves of 390 million boe related to 21 fields and field developments in several West and North African countries; Algeria, Angola, Libya and Nigeria. Angola is the major contributor to the proved reserves in this area, with 16 of the 21 fields.

All fields are in production in Algeria and Nigeria. Production from the Mabruk and Murzuq fields in Libya was stopped in February 2011 due to political unrest in the country, but has now resumed.

In Angola we have proved reserves in four blocks; Block 4, Block 15, Block 17 and Block 31, with production from all blocks except Block 31. Four discoveries in Block 17, called the CLOV project, and two discoveries in Block 15, Clochas and Mavacola, are under development. In Block 31, all four discoveries in the PSVM project are under development.

Of the total proved reserves in Africa, 272 million boe or 70% are proved developed reserves. 80% of the total proved reserves in this area are oil reserves and 20% are gas reserves.



Proved reserves in the Americas

In North and South America, we have proved reserves equal to 650 million boe in a total of 19 fields and field development projects. This represents 12% of our total proved reserves. Fourteen of these fields are located in the United States (USA), four in Canada and two in South America. The most important new contribution to our reserves is the Bakken asset, from the acquisition of Brigham Exploration Company in late 2011, adding 122 million boe of proved reserves. These are primarily reserves in the Bakken and Three Fork tight oil plays in the Williston basin, located principally in the state of North Dakota in the USA.

In the USA, six out of ten fields in the Gulf of Mexico and the onshore tight reservoir assets Marcellus, Eagle Ford, Bakken and Three Forks are all in production. In the Gulf of Mexico, field development is ongoing at Caesar Tonga, Big Foot, Jack and St. Malo. The Big Foot development is carrying economic proved reserves for the first time from 2011. Further drilling in the Marcellus and Eagle Ford assets has increased the proved reserves in 2011, and these additions are expressed as extensions.

The Hibernia South Extension field off the coast of Canada was sanctioned and started production during 2011, and it is carrying proved reserves for the first time. In Canada, proved reserves are related both to offshore field developments and to the Leismer Demonstration Project in our oil sands leases in Alberta.

In 2010, we announced the sales of a 40% interest in the Peregrino field in Brazil and a 40% interest in the oil sands leases in Alberta, Canada. These sales have now been approved and the effect on the 2011 proved reserves statement is 66 million boe sale of reserves-in-place.

3.9.1 Development of reserves

In 2011, we converted approximately 230 million boe from undeveloped to developed proved reserves.

Start-up of production from the Hibernia South Extension off the coast of Canada, Pazflor in block 17 in Angola and Peregrino in Brazil increased our developed reserves by 54 million boe during the year. The rest of the converted volume is related to development activities on producing fields.

The sanctioning of new projects, such as Hild, Hyme, Skuld, Stjerne and Svalin (M structure) in Norway, Hibernia South Extension off the coast of Canada and Big Foot in the Gulf of Mexico added a total of 97 million boe of proved undeveloped reserves in 2011. In addition, the Brigham acquisition in late 2011 added significant volumes to both our proved developed and undeveloped reserves.

		Oil and NGL (mmbbls)	Natural gas (bcf)	Total (mmboe)
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	14,700	3,976
	Undeveloped	767	3,265	1,349
2009	Proved reserves end of year	2,174	18,148	5,408
	Developed	1,442	14,990	4,113
	Undeveloped	733	3,158	1,295

As of 31 December 2011, the total proved undeveloped oil and gas reserves amounted to 1,599 million boe, 62% of which are related to fields in Norway. The Snøhvit, Troll and Tyrihans fields, with continuous development activities, represent the largest undeveloped assets in Norway together with fields not yet in production, such as Skarv, Gudrun, Goliat and Valemon. The positive change in total proved undeveloped reserves for Norway in 2011 is linked to inclusion of the new developments sanctioned in 2011, with Skuld and Hild being the most important. Moreover, significant positive revisions for our NCS producing fields have increased both the developed and undeveloped proved reserves. The largest assets with respect to undeveloped proved reserves outside Norway are Peregrino in Brazil and Petrocdeño in Venezuela, together with the US onshore developments in Bakken, Marcellus and Eagle Ford. The increase in proved undeveloped reserves outside Norway in 2011 is partially due to the inclusion of the Bakken reserves, but also to an increase for other onshore developments in this region as a consequence of drilling progress during the year.

In 2011, Statoil incurred NOK 70 billion in development costs relating to assets carrying proved reserves, NOK 51 billion of which was related to moving proved undeveloped reserves to developed reserves.

Due to the nature of large fields with continuous development activity, such as Heidrun, Oseberg, Snøhvit and Troll in Norway, Azeri-Chirag-Gunashli in Azerbaijan, Leismer oil sands in Canada (SAGD) and Petrocedeño in Venezuela, these fields contain reserves that are expected to remain undeveloped for five years or more. All these projects are large field developments, five of them offshore, with several billion dollar investments having been made in complex infrastructure. The development of these fields will require extensive, sustained drilling of wells for a long period of time. A large proportion of the central facilities are already in place, and a significant part of the total investments have been made. It is highly unlikely that these field development projects will be prematurely terminated, since this would result in a significant loss of capital. 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. Construction of the final pipeline section has now commenced and the field is anticipated to start production in 2014.

Additional information about proved oil and gas reserves is provided in note 33 - *Supplementary oil and gas information* - to our consolidated financial statements.

3.9.2 Preparations of reserves estimates

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

The Corporate Reserves Management (CRM) team consists of experts 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, with the exception of the 2011 proved reserves in the Bakken asset representing 2.3% of our total proved reserves, which have been prepared by the external petroleum engineering consultants Cawley, Gillespie & Associates, Inc. (CG&A). A report summarising CG&A's evaluation is included as Exhibit 15 (a)(v).

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 signed off 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 and finally presented to the board's audit 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 26 years' experience in the oil and gas industry, 25 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 2011. The evaluation accounts for 98% of Statoil's proved reserves and does not include the assets related to the acquisition of Brigham Exploration Company in late 2011. 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 2011	Oil, Condensate and LPG (mmbbls)	Sales Gas (bcf)	Oil Equivalent (mmboe)
Estimated by Statoil	2,170	17,591	5,304
Estimated by DeGolyer and MacNaughton	2,190	18,426	5,473

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

3.9.3 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 2011.

A gross value reflects wells or acreage in which we have interests (presented as 100%). The net value corresponds to the sum of the whole or fractional working interest for Statoil in gross wells or acreage.

At 31 December 2011	Norway	Eurasia excluding Norway	Africa	Americas	Total
Number of productive oil and gas wells					
Oil wells — gross	800	144	347	1,216	2,507
— net	288.0	19.1	51.3	209.5	568.0
Gas wells — gross	193	42	65	649	949
— net	86.6	14.5	24.2	161.2	286.5

The total gross number of productive wells at the end of 2011 includes 383 oil wells and 20 gas wells with multiple completions or wells with more than one branch.

At 31 December 2011 (in thousands of acres)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Developed and undeveloped oil and gas acreage					
Acreage developed — gross	788	196	961	561	2,506
— net	290	52	297	218	857
Acreage undeveloped — gross	10,994	20,093	25,325	10,923	67,334
— net	4,848	6,691	11,956	5,100	28,595

The largest concentrations of developed acreage in Norway are in 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 now in Indonesia with some 57% of the total of this geographical area. In 2011 we acquired six new licenses in Indonesia, with Halmahera II representing the largest acreage. Our largest acreage concentration in Africa is the Hassi Mouina blocks in Algeria representing about one-third of the total net acreage in Africa.

After the acquisition of Brigham Exploration Company (Bakken), together with the acreage in the Marcellus and Eagle Ford plays, most of our developed and undeveloped acreage in the Americas is now located onshore USA, some 25% of our net acreages in Americas. Also the offshore acreage in Gulf of Mexico represents a large share of the undeveloped acreage with some 20% of our net acreages in Americas. Significant parts of our acreage in this region are also related to the Camamu-Almada Basin off the coast of Brazil, the oil sands areas located in the Athabasca region of Alberta, Canada, and our licences off the coast of Newfoundland, Canada.

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 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
Year 2009					
Net productive and dry exploratory wells drilled	21.3	0.9	4.4	2.8	29.3
— Net dry exploratory wells drilled	9.6	0.3	2.1	1.0	13.0
— Net productive exploratory wells drilled	11.7	0.6	2.2	1.8	16.3
Net productive and dry development wells drilled	25.7	4.6	8.1	13.9	52.3
— Net dry development wells drilled	1.2	0.4	0.7	0.0	2.3
— Net productive development wells drilled	24.5	4.2	7.3	13.9	50.0

In connection with our oil sands development in the Athabasca region of Alberta, we also drilled 62 wells in 2011 to map and delineate the bitumen pay. All of these wells were logged and 44 wells were cored.

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 2011

	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2011					
Number of wells in progress					
Development Wells					
— gross	45	5	20	332	402
— net	16.5	0.8	3.9	95.3	116.5
Exploratory Wells					
— gross	4	2	1	3	10
— net	1.9	0.6	0.2	0.7	3.4

3.9.4 Delivery commitments

A stable level of long-term commitments for contract years 2011-2014.

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 will deliver gas to customers under various types of sales contracts. In order to fulfil the commitments, we will 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 annual contract quantities (ACQ). As of 31 December 2011, the long-term commitments from NCS for the Statoil/SDFI arrangement amounted to a total of approximately 24 tcf (675 bcm).

In the contract years 2011 to 2014, the total ACQ for the respective years are: 2.23, 2.27, 2.30 and 2.30 tcf (63.2, 64.3, 65.2 and 65.1 bcm) per year. Our currently developed gas reserves in Norway are more than sufficient to meet our share of these commitments for the next three years.

3.10 Applicable laws and regulations

The principal legislation governing our petroleum activities in Norway is the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

The principal legislation governing our petroleum activities in Norway and on the NCS is 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 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 section *Risk review - Risk factors - Risks related to ownership by the principal shareholder and its involvement in the SDFI 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 regulation 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.

3.10.1 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 power to award and set the terms for production licences.

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

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 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. Notwithstanding the exclusive rights granted under a production licence, the Ministry of Petroleum and Energy has the power, in exceptional cases, to permit third parties to carry out exploration in the area covered by a production licence.

Production licences are normally awarded in licensing rounds. The first licensing round for NCS production licences was announced in 1965. The award of the first licences covered areas in the North Sea. Over the years, the awarding of licences has moved northward to cover areas in both the Norwegian Sea and the Barents Sea. In recent years, the principal licensing rounds have largely concerned licences in the Norwegian Sea. However, in the future, we expect an increase in licensing rounds concerning 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. As is the case for most fields on the NCS, our production activities are conducted through joint venture arrangements with other companies and, in some cases, with the Norwegian State through its wholly-owned company Petoro AS. 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 veto power 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. However, with the consent of the Ministry of Petroleum and Energy, the management committee may instruct the operator to continue to perform its duties until a new operator has been appointed. 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. Until the PDO has been approved by the Ministry of Petroleum and Energy, the licensees cannot undertake material contractual obligations or commence construction work without the prior consent of 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. The work obligation will typically include seismic surveying and/or exploration drilling. 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, but only to a percentage of the area, typically 50%. 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, the owners, who in practice are licensees under a production licence, 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 of a group of licence holders. 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.

3.10.2 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. In 2009, the European Commission issued a third legislative package for an internal EU gas and electricity market. It has yet to be fully implemented in the EU Member States' national laws, however.

The Norwegian gas transport system, that is to say the pipelines and the terminals through which all licensees on the NCS transport their gas, is owned by a joint venture, Gassled. The joint ownership structure is intended to ensure the effectiveness of the system and to prevent conflicts of interest. The Norwegian Petroleum Act of 29 November 1996 establishes the basis for non-discriminatory third-party access to the Gassled transport system. The pertaining Petroleum Regulations set out the objective and non-discriminatory provisions for access to available capacity. The access regime provided for therein consists of a regulated primary market where the right to book spare capacity is allocated to users with a need to transport natural gas. The access regime also allows for a secondary market where capacity can be transferred between users after allocation in the primary market if transportation needs have changed after the initial booking.

To further ensure neutrality, the petroleum regulations stipulate that all booking and allocation of capacity is based on standard procedures and administrated by an independent system operator, Gassco AS, a company wholly owned by the Norwegian State. Spare capacity is released for pre-defined time periods at announced points in time and with specific time limits within which bookings must be placed with the operator online. If the total of the bookings exceeds the spare capacity, the spare capacity is allocated to the shippers of gas by applying an allocation formula. If there is no available capacity in the booking system and some of the reserved capacity is not utilised, Gassco may make the unutilised capacity available to other shippers on an interruptible basis.

The tariffs for 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 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. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported.

For further information, see *Operational Review - Marketing, Processing and Renewable Energy - Natural Gas - Norway's gas transport system*.

3.10.3 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 were imposed.

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 2012. If enforced in the EU and subsequently adopted in the European Economic Area (EEA) of which Norway is part, the regulation would apply to our activities on the NCS. The effects, if any, of it are not possible to foresee until the legislative process is finalised.

In 2001, Statoil established a system for monitoring the technical safety of its facilities and plants. As part of this system, it collects and interprets information from, and incorporates risk management into, its operating activities.

The Petroleum Safety Authority Norway has the regulatory responsibility for safety, emergency preparedness and the working environment for all offshore and onshore petroleum-related activities in Norway. Following the Macondo incident, permission from the Petroleum Safety Authority Norway to start drilling a new well is now dependent on the applicant's ability to handle a potential blow-out, and the applicant must demonstrate the actions it would undertake to shut down the affected well.

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.

In our capacity as holder of licences under the Petroleum Act, we are subject to strict statutory liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licences. This means that anyone who suffers damage or loss as a result of pollution from any of our NCS licence areas can claim compensation from us regardless of whether the claimant can demonstrate fault on our part. If the pollution is caused by a *force majeure* event, a Norwegian court may reduce the damages to a level it considers reasonable.

International

With business operations in 41 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 addition, current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws could have a significant effect on the production, sale and profitability of many of our products. There are also environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorised release of hazardous materials or petroleum associated with our operations. These laws may apply to sites that Statoil currently owns or operates, sites that it or its predecessors' previously owned or operated or sites used for the disposal of its and other parties' waste.

We anticipate that the HSE laws and regulations to which we are subject, both in Norway and around the world, are likely to have an increasing impact on our operations. It is difficult, however, to accurately predict the effects of future legislative developments in this regard on our future earnings and operations. Some risk of HSE costs and liabilities is inherent in our activities, which is also the case for our peers in the industry. We cannot guarantee that material costs and liabilities will not be incurred; however, we do not currently expect any material adverse effects on our financial position or results of operations relating to compliance with such laws and regulations.

3.10.4 Taxation of Statoil

We are subject to ordinary Norwegian corporate income tax and to a special petroleum tax relating to our activities offshore Norway. Our NCS activities are also subject to a special carbon dioxide emissions tax and a nitrogen oxide tax in Norway.

Under our production licences, we are obliged to pay an area fee to the Norwegian State. Below is a summary of certain key aspects of the Norwegian tax rules that apply to our operations.

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 Taxation 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 related 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.

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. Dividends from low-tax countries or portfolio investments outside the EEA will, under certain circumstances, be subject to the standard 28% income tax rate based on the full amounts received.

Capital gains from the realisation of shares are taxable. The basis for taxation is 3% of the gain, which is subject to the standard 28% income tax. Capital losses from the realisation of shares are not deductible. Exceptions apply to shares held in companies domiciled in low-tax countries or portfolio investments outside the EEA, 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.

Abandonment costs

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

Carbon dioxide emissions tax

A special carbon dioxide emissions tax applies to petroleum activities on the NCS. For 2011, the tax was NOK 0.48 and for 2012 it is NOK 0.49 per standard cubic metre of gas burned or directly released and per litre of oil burned. In addition, companies operating on the NCS have to buy allowances to cover carbon dioxide emissions from petroleum activities.

Nitrogen oxide emissions tax

With effect from 1 January 2007, the Norwegian government introduced a nitrogen oxide tax applicable to emissions of nitrogen oxide on the NCS. The tax was NOK 16.43 per kilogram of nitrogen oxide for 2011 and it is NOK 16.69 for 2012.

As an alternative to paying the nitrogen oxide tax, companies can voluntarily agree to contribute to an industry nitrogen oxide fund. A fund agreement has been signed for the years 2011-2017. The contribution to the fund is NOK 11 per kilogram of nitrogen oxide emissions. We have entered into an agreement to contribute to the fund.

Area fee

After the expiry of the initial exploration period, the holders of production licences are required to pay an area fee. The amount of the area fee is stipulated in regulations issued under the Petroleum Act. For most of the production licences, the initial annual area fee is currently NOK 30,000 per square kilometre. For the next year, the fee is increased to NOK 60,000 per square kilometre, and the annual fee increases to NOK 120,000 per square kilometre thereafter. Production licences for which a PDO has been submitted are, from the time of submission of the PDO and for as long as extraction from the deposit takes place, exempt from the obligation to pay the area fee for the area defining the deposits included in the PDO.

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.

Generally, income from Statoil's upstream production outside Norway is subject to tax at the higher of the Norwegian onshore rate (28%) or the prevailing tax rate in the countries in which it operates. Statoil is subject to excess (or "windfall") profit tax in some of the countries in which it produces crude oil.

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 is 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 producing 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 not negotiable and the company is subject to legislative changes in the tax laws.

3.10.5 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.

3.10.6 SDFI oil & gas marketing & 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 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 the production licence. 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 now 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.

3.11 Competition

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. Oil and gas prices and demand, exploration and production costs, global production levels, alternative fuels, and government - including environmental - regulations are key factors affecting competition in the oil and gas industry.

Statoil's ability to remain competitive will depend, among other things, on its management continuing to focus on reducing unit costs and improving efficiency, maintaining long-term growth in our 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.

3.12 Property, plants and equipment

We have interests in real estate in many countries throughout the world, but no one individual property is significant to us as a whole.

Our head office, which is located at Forusbeen 50, N-4035, Stavanger, Norway, comprises approximately 135,000 square metres of office space and is owned by Statoil.

During 2011, Statoil's new 65,500-square-metre office building located on the outskirts of Norway's capital Oslo was under construction in accordance with the long-term lease agreement signed in 2010 between Statoil as tenant and IT-Fornebu AS as owner. The new office will provide an environmentally friendly workplace for up to 2,500 employees. The building will be made available to Statoil by 1 September 2012 at the latest, and the move to the new offices is planned to be completed in mid-October 2012.

For a description of our significant reserves and sources of oil and natural gas, see note 33 - *Supplementary oil and gas information* in the consolidated financial statements in this report.

3.13 Related party transactions

We have the following transactions with related parties.

Transactions with the Norwegian State

For a description of shares held by the Norwegian State, see the section *Shareholder information-Major shareholders*.

Transactions with other entities in which the Norwegian State is a major shareholder

Because the Norwegian State controls a substantial proportion of the industry in Norway, there are many state-controlled entities with which we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State in such counterparties has not had any effect on the arm's-length nature of the transactions. A full overview of the Norwegian State's shareholdings in commercial entities can be found here:

www.regjeringen.no/nb/dep/nhd/tema/eierskap/statlig-eierskap/forvaltning-av-statlige-eierandeler.html?id=383095

Other transactions with the Norwegian State

Total purchases of oil and natural gas liquids from the Norwegian State amounted to NOK 95.5 billion (161 million boe), NOK 81.4 billion (176 million boe) and NOK 74.3 billion (204 million boe) in 2011, 2010 and 2009, respectively. Purchases of natural gas from the Tjeldbergodden methanol plant amounted to NOK 0.4 billion, NOK 0.4 billion and NOK 0.3 billion in 2011, 2010 and 2009, respectively.

The significant amounts included under the item *Payables to equity accounted investments and other related parties* in note 25 *Trade and other payables to the financial statements*, are amounts payable to the Norwegian State for these purchases. The prices paid by Statoil for the oil purchased from the Norwegian State are estimated at market prices. In addition, Statoil sells the Norwegian State's natural gas in its own name, but for the account and risk of the Norwegian State.

The Norwegian State compensates Statoil for its relative share of the costs related to certain Statoil natural gas storage and terminal investments and related activities. See the section *Operational review- Applicable laws and regulations-SDFI oil & gas marketing & sale* for more details.

Although the Norwegian State is Statoil's majority owner, Statoil is not given preferential treatment with respect to licences granted by the Norwegian State or under any other regulatory rules enforced by the Norwegian State.

Employee loans

All Statoil ASA employees can apply for a consumer loan of up to NOK 300,000. As of 1 November, 2011 these loans are administered and disbursed by Statoil ASA. Prior to 1 November 2011, we had a general arrangement with the bank Den norske Bank (DnB). The employees pay the "norm interest rate", which is variable and set by the Norwegian State.

Members of the corporate executive committee and the board of directors may not take up loans under the current programme. None of the three employee-elected members of the board of directors and none of members of the corporate executive committee had any balances outstanding under this arrangement as of 12 March 2012.

Employees at certain levels are entitled to an interest-free car loan from the company. Members of the corporate executive committee and employee-elected members of the board are generally excluded from this arrangement, and none of them had any balances outstanding as of 12 March 2012.

Family members of corporate executive committee members or directors, who are also employees of Statoil, may participate in the employee loan and/or car loan programmes and may have balances outstanding.

Statoil's corporate assembly includes six employee representatives and three employee observers who, as part of their remuneration, may have balances outstanding under the company's employee loan and/or car loan programmes.

Other related party transactions

In the ordinary course of our business, we enter into transactions with various organisations with which some of the members of Statoil's corporate assembly, board of directors or corporate executive committee are associated. Except as described in this report, Statoil did not have material transactions or transactions of an unusual nature with related parties in the period covered by this report.

3.14 Insurance

Among other things, 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.

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 8,500 million per incident for exploration wells
- NOK 2,000 million per incident for production wells.

GoM

- USD 1,300 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 insurances will adequately protect us against liability for all potential consequences or damages.

3.15 People and the group

Statoil's overall strategic objective is to build a globally competitive company and an exceptional place to perform and develop.

During the last few years, Statoil has expanded into new business activities, both geographically and into emerging technologies, such as deepwaters, heavy oil and shale gas. In order to succeed in these activities, we must have the right organisational and people capabilities, as well as the ability to attract new talents globally.

Through global people policies, Statoil aims to ensure consistent common standards across the organisation. Together with our values and ethics code of conduct, our people policies are the most important guidelines for the people processes. We endeavour to ensure a good match between the professional interests and goals of every employee and the needs of the business. Through our global development and deployment process, we endeavour to offer

challenging and meaningful job opportunities. Statoil remains committed to providing financial and non-financial rewards that attract and motivate the right people, and it continues to focus on equal opportunities for all employees.

Through the Statoil 2011 reorganisation, effective from 1 January 2011, Statoil has accelerated the development of new leaders, and significantly expanded the proportion of female and international leaders.

3.15.1 Employees in Statoil

The Statoil group employs approximately 32,000 employees. Of these were approximately 10,400 employees within the Statoil Fuel & Retail group, of which we held a 54% majority ownership interest as of 31 December 2011. Approximately 20,000 of Statoil group's employees are employed in Norway and approximately 12,000 outside Norway.

Numbers of permanent employees* and percentage of women in the Statoil group from 2009 to 2011

Geographical Region	Number of employees			Women		
	2011	2010	2009	2011	2010	2009
Norway	20,021	18,838	18,100	31%	31%	31%
Rest of Europe	10,187	10,335	9,593	50%	49%	50%
Africa	121	140	165	28%	30%	28%
Asia	146	145	150	59%	58%	55%
North America	1,030	713	584	34%	33%	34%
South America	210	173	147	40%	46%	48%
TOTAL	31,715	30,344	28,739	37%	37%	37%
Non - OECD	2,773	2,732	2,703	64%	63%	64%

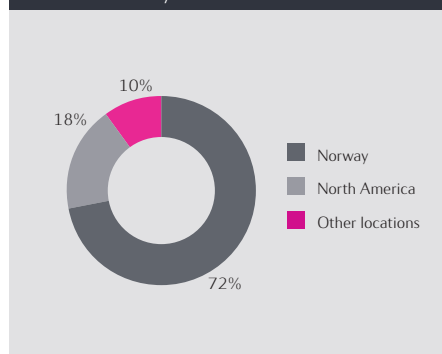
* Statoil Fuel and Retail employees are included

Geographical Region	Permanent employees 2011	Consultants	Total Workforce*	% Consultants**	% Part - Time	New Hires
Norway	20,021	4758	24,779	19%	3%	1697
Rest of Europe	10,187	2460	12,647	19%	1%	1849
Africa	121	43	164	26%	NA	6
Asia	146	22	168	13%	NA	30
North America	1,030	138	1,168	12%	NA	352
South America	210	299	509	59%	NA	51
TOTAL	31,715	7,720	39,435	20%	3%	3985
Non - OECD	2,773	437	3210	14%	NA	594

* Total workforce consists of number of permanent employees and consultants

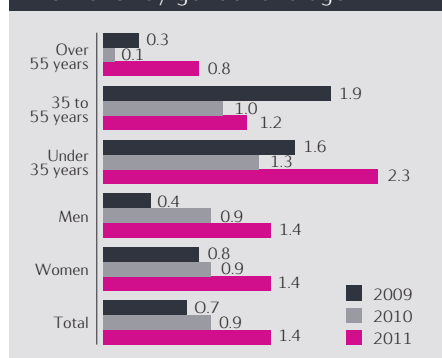
** Consultants do not include enterprise personnel

New hires by location



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 2011, Statoil recruited 1,900 new employees worldwide. While 70% were recruited to jobs in Norway, 18% were recruited to our business in North America, reflecting our growth ambitions in that region. In 2011, 43% of our new hires were women and 65% other nationalities than Norwegian.

Turnover by gender and age



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 ASA, the total turnover rate for 2011 was 1.4%. The figure opposite provides an overview of the total turnover rate by gender and age in Statoil ASA from 2009 to 2011 (number excluding the reporting segment SFR).

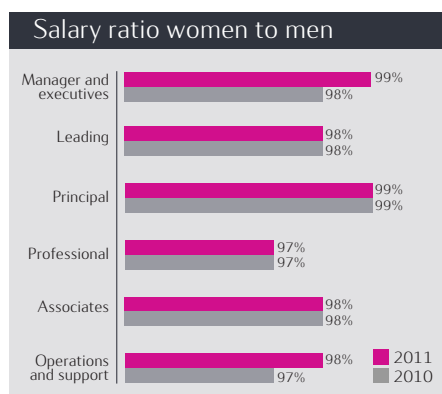
3.15.2 Equal opportunities

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

At 31 December 2011, the overall percentage of women in the company was 37%, and 40% of the board of directors were women, and 20% of the corporate executive team were women. 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 the end of December 2011, the total proportion of female managers in Statoil was 31%, and, among managers under the age of 45, the proportion was 32% (number excluding the reporting segment SFR).

We also devote close attention to male-dominated positions and discipline areas. In 2011, 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

We believe 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. 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 year end 2011, 41% of the managerial staff in the Statoil group held nationalities other than Norwegian.

3.15.3 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, 68% 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.

During 2011, management and employee representatives have collaborated closely in important processes such as the evaluation of the offshore operations model and measures to follow up safety incidents on the NCS. In these processes we believe that we have endeavoured to engage in open and honest communication both inside and outside formal meeting arenas.

4 Financial analysis and review

Statoil delivered strong financial results and cash flows in 2011. Production was lower than 2010 but in line with expectations and important strategic progress was made. Discoveries were made in 22 out of 41 exploration wells.

Net operating income was up by 54% compared with 2010. Net operating income in 2011 was positively impacted by higher prices for both liquids and gas, unrealised gains on derivatives, gains on sale of assets mainly related to the reduction of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled. Reduced net impairment losses also added to the increase in net operating income. Lower volumes of both liquids and gas sold and increased operating expenses partly offset the increase in net operating income.

Strategic portfolio optimisation in 2011 included the sale of interests in Peregrino and Kai Kos Dehseh oil sands, the Gassled divestment and the Brigham acquisition. The NCS portfolio was further streamlined through a farm down agreement of assets with Centrica, which is expected to be closed in the second quarter of 2012.

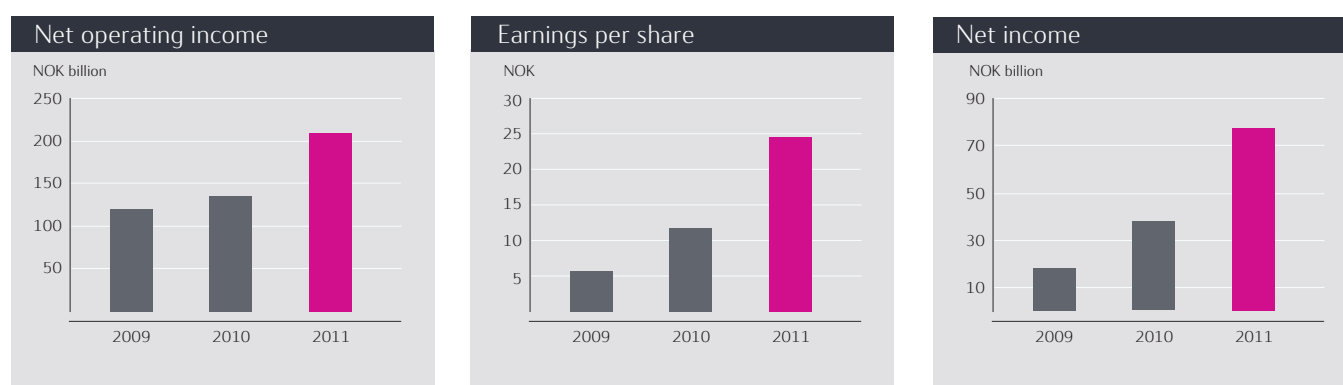
Statoil achieved a reserve replacement ratio (RRR) of 1.17 in 2011, of which the organic RRR was above 1.0. The RRR for oil was 1.45, including the effect of sales and purchases.

The board of directors is proposing a dividend of NOK 6.50 per share for 2011.

As stated in note 2 *Significant accounting policies*, Statoil changed its policy for accounting for jointly controlled entities under IAS 31 Interests in Joint Ventures, from the application of the equity method to the proportionate consolidation method with effect from 2011. Proportionate consolidation has been retrospectively applied in the consolidated financial statements, and the years ended 31 December 2010 and 2009 have been restated accordingly.

4.1 Operating and financial review 2011

Statoil delivered strong financial results and strong cash flows in 2011, despite reduced production and increased operating expenses.



In 2011, Statoil delivered total entitlement liquids and gas production of 1,650 mboe per day, down 3% from 1,705 mboe per day in 2010. Total equity liquids and gas production decreased by 2% from 2010, to 1,850 mboe per day in 2011, mainly caused by reduced water injection at Gullfaks, challenges primarily related to risers, 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.

Despite reduced production, net operating income was up 54% at NOK 211.8 billion in 2011, compared to NOK 137.3 billion in 2010. The increase was mainly 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 sale of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled in 2011. Lower volumes of both liquids and gas sold, increased operating expenses and net impairment losses partly offset the increase in net operating income.

Statoil's exploration programme for 2011 totalled 41 exploration wells completed before 31 December 2011. Sixteen of them were drilled outside the Norwegian continental shelf (NCS). A total of 22 wells were announced as discoveries during 2011. Seventeen of them are located on the NCS.

In 2011, 599 mmboe of proved reserves were added through revisions, extensions and discoveries, compared to additions of 526 mmboe in 2010, also through revisions, extensions and discoveries.

Statoil achieved a reserve replacement ratio of 117% in 2011, compared to 87% in 2010. The increase in 2011 is related to positive revisions of the proved reserves in several of our producing fields, newly sanctioned field development and increased recovery projects, several new wells in production in the Marcellus and the Eagle Ford shale gas acreage and purchase of the Bakken oil play in North America.

Statoil progressed two new projects into production in 2011: the Peregrino field in Brazil and the Pazflor field in Angola both came on stream.

4.1.1 Sales volumes

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

We take part in the production of oil and natural gas volumes, and incur capital expenditures and operating expenses on the basis of such equity volumes. Under certain production-sharing agreements (PSAs), a portion of the equity production is distributed to the relevant government before arriving at the volumes that we are ultimately entitled to sell (entitlement volumes). The timing of our lifting of our share of entitlement volumes may cause there to be a difference at any given time between our share of entitlement volumes and the volumes lifted. This difference is called overlift if we have lifted more than our share of the entitlement production, and underlift if our cumulative lifting is less than our share of the entitlement volumes. The lifted volumes and volumes in inventory are the basis for what we can sell to third parties. Revenues are based on lifted volumes.

In addition to our own volumes of lifted entitlement production and production in storage, 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 *Operational review - Applicable laws and regulations- SDFI oil & gas marketing & sale*. The following table shows SDFI and Statoil sales volume information for crude oil and natural gas, as applicable, 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 analysis and review - Operating and financial review 2011 - Definitions of reported volumes*.

Sales Volumes	Year ended December 31		
	2011	2010	2009
Statoil: ⁽¹⁾			
Crude oil (mmbbls) ⁽²⁾	332	354	381
Natural gas (bcf)	1,377	1,472	1,462
Natural gas (bcm) ⁽³⁾	39.0	41.7	41.4
Combined oil and gas (mmboe)	577	616	642
Third party volumes: ⁽⁴⁾			
Crude oil (mmbbls) ⁽²⁾	333	310	257
Natural gas (bcf)	244	247	192
Natural gas (bcm) ⁽³⁾	6.9	7.0	5.4
Combined oil and gas (mmboe)	376	354	291
SDFI assets owned by the Norwegian State:			
Crude oil (mmbbls) ⁽²⁾	162	172	200
Natural gas (bcf)	1,476	1,610	1,431
Natural gas (bcm) ⁽³⁾	41.8	45.6	40.5
Combined oil and gas (mmboe)	425	458	455
Total			
Crude oil (mmbbls) ⁽²⁾	827	835	838
Natural gas (bcf)	3,096	3,329	3,085
Natural gas (bcm) ⁽³⁾	87.7	94.3	87.4
Combined oil and gas (mmboe)	1,378	1,428	1,388

⁽¹⁾ The Statoil volumes included in the table above are based on the premise 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.

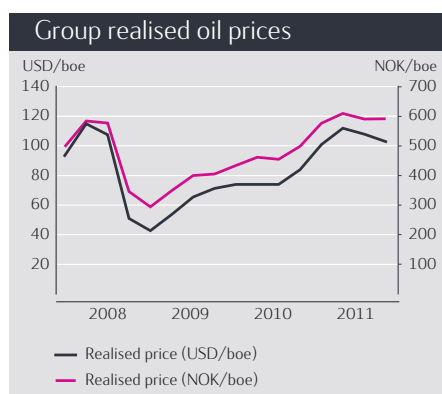
⁽⁴⁾ Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG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

4.1.2 Group profit and loss analysis

Net operating income was NOK 211.8 billion in 2011, a 54% increase compared to 2010 mainly due to higher prices, reduced net impairment losses, unrealised gains on derivatives and gains on sale of assets.

IFRS Income statement (in NOK billion)	2011	For the year ended 31 December		11-10 change	10-09 change
		2010 (restated)	2009 (restated)		
Revenues and other income					
Revenues	645.6	527.0	462.5	23%	14%
Net income from associated companies	1.3	1.2	1.5	8%	(20%)
Other income	23.3	1.8	1.4	>100%	31%
Total revenues and other income	670.2	529.9	465.4	26%	14%
Operating expenses					
Purchase [net of inventory variation]	319.6	257.4	205.9	24%	25%
Operating expenses and Selling, general and administrative expenses	73.6	68.8	67.3	7%	2%
Depreciation, amortisation and net impairment losses	51.4	50.7	53.8	1%	(6%)
Exploration expenses	13.8	15.8	16.7	(12%)	(5%)
Total operating expenses	(458.4)	(392.7)	(343.7)	17%	14%
Net operating income	211.8	137.3	121.7	54%	13%
Net financial items	2.1	(0.4)	(6.8)	>100 %	(94%)
Income before tax	213.8	136.8	114.9	56%	19%
Income tax	(135.4)	(99.2)	(97.2)	37%	2%
Net income	78.4	37.6	17.7	>100%	>100%
Earnings per share for income attributable to equity holders of the company diluted	24.7	11.9	5.7	>100%	>100%

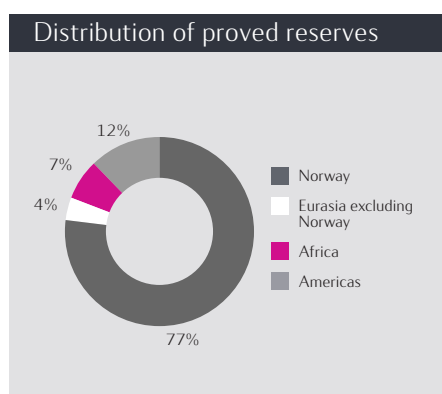
Operational data	2011	For the year ended 2010	2009	11-10 Change	10-09 Change
Average liquids price (USD/bbl)	105.6	76.5	58.0	38 %	32 %
USDNOK average daily exchange rate	5.61	6.05	6.30	(7 %)	(4 %)
Average liquids price (NOK/bbl)	592	462	364	28 %	27 %
Average gas prices (NOK/scm)	2.08	1.72	1.90	21 %	(10 %)
Refining reference margin (USD/bbl)	2.3	3.9	3.0	(41 %)	30 %
Total entitlement liquids production (mboe per day)	945	968	1,066	(2 %)	(9 %)
Total entitlement gas production (mboe per day)	706	738	740	(4 %)	(0 %)
Total entitlement liquids and gas production (mboe per day)	1,650	1,705	1,806	(3 %)	(6 %)
Total equity liquids production (mboe per day)	1,118	1,122	1,202	(0 %)	(7 %)
Total equity gas production (mboe per day)	732	766	760	(4 %)	1 %
Total equity liquids and gas production (mboe per day)	1,850	1,888	1,962	(2 %)	(4 %)
Total liquids liftings (mboe per day)	910	969	1,045	(6 %)	(7 %)
Total gas liftings (mboe per day)	706	738	740	(4 %)	(0 %)
Total liquids and gas liftings (mboe per day)	1,616	1,706	1,785	(5 %)	(4 %)
Production cost entitlement volumes (NOK/boe, last 12 months)	48.4	42.8	38.4	13 %	11 %
Production cost equity volumes (NOK/boe, last 12 months)	43.1	38.6	35.3	12 %	9 %
Equity production cost excluding restructuring and gas injection cost (NOK/boe, last 12 months)	42.4	37.9	35.3	12 %	7 %



Total revenues and other income amounted to NOK 670.2 billion in 2011 compared to NOK 529.9 billion in 2010 and NOK 465.4 billion in 2009. 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 sales, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net.

The NOK 118.6 billion increase in **revenues** from 2010 to 2011 was mainly attributable to higher prices for both liquids and gas, partly offset by lower volumes of both liquids and gas sold. The variance on unrealised net gains on derivatives contributed NOK 12.0 billion to the increase in revenues between the years. Average prices of liquids measured in NOK increased by 28% from 2010 to 2011, contributing NOK 43.2 billion to the increase in revenues, while average gas prices measured in NOK increased by 21%, contributing NOK 18.3 billion. The increase was partly offset by a 6% decrease in liftings of liquids and a 4% decrease in total liftings of gas, with off-setting effects of NOK 9.9 billion and NOK 4.1 billion, respectively.

The NOK 64.5 billion increase in revenues from 2009 to 2010 was mainly attributable to higher prices for liquids and increased volumes of gas sold, partly offset by lower gas prices, reduced volumes of liquids sold and losses on derivatives. Realised prices of liquids measured in NOK increased by 27% from 2009 to 2010, contributing NOK 34.6 billion to the increase in revenues, while increased volumes of gas sold contributed NOK 5.9 billion to the increase in revenues. The increase was partly offset by a 7% decrease in liftings of liquids with a negative contribution of NOK 10.1 billion, while gas prices were down by 10% in 2010, affecting revenues negatively by NOK 9.5 billion.

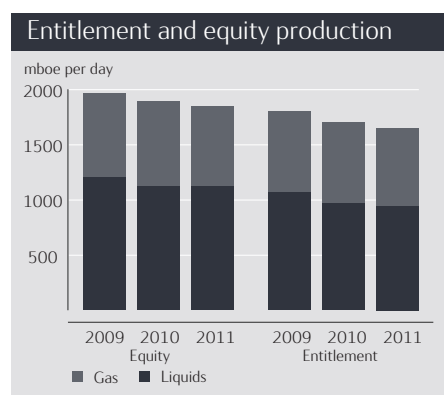


Over time, the volumes lifted and sold will equal our production of entitlement volumes, but they may be higher or lower in any period due to differences between the capacity of the vessels lifting our volumes and the actual entitlement production in the period.

Total liquids **liftings** were 910 mboe per day in 2011, a decrease of 6% compared to 2010. Total liquids liftings were 969 mboe per day in 2010, a decrease of 7% compared to 2009 when total liquids liftings were 1,045 mboe per day. The average underlift was 34 mboe per day in 2011. In 2010, the average overlift was 1 mboe per day and in 2009, the average underlift was 21 mboe per day.

Entitlement volumes lifted form the basis for revenue recognition, while equity production volumes affect operating costs more directly. See the report section *Financial analysis and review - Operating and financial review 2011 - Sales volumes*, for more details on the production-sharing agreement (PSA) effects that cause differences between equity and entitlement volumes. See below for more details on the difference between lifted and produced volumes.

Total entitlement liquids and gas production decreased from 1.705 mmboe per day in 2010 to 1.650 mmboe per day in 2011. In 2009, total entitlement liquids and gas production was 1.806 mmboe per day.



Total equity liquids and gas production decreased from 1.888 mmboe per day in 2010 to 1.850 mmboe per day in 2011. In 2009, total equity production of liquids and gas was 1.962 mmboe per day.

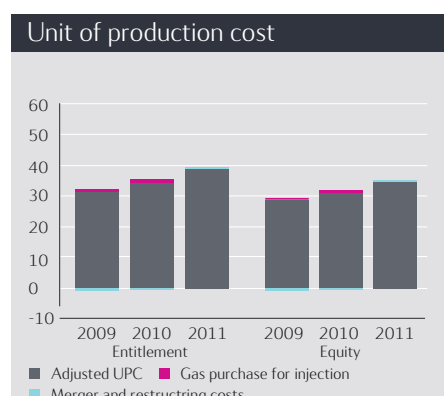
The 2% decrease in total equity production in 2011 compared to 2010 was primarily caused by reduced water injection at Gullfaks, riser inspections and repairs, maintenance shut downs and deferral of gas sales. In addition, expected reductions due to natural decline on mature fields and suspended production 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 production decreased by 6% from 2010 to 2011 and was impacted by the reduction in equity production and by increasing PSA effects.

The 4% decrease in total equity production in 2010 compared to 2009, was primarily caused by relatively higher maintenance activity in 2010 leading to production shutdowns, limitations in the gas transportation system from the NCS because of planned maintenance, production permit restrictions on the Ormen Lange field, various operational issues and a natural production decline on several mature fields. The decrease in equity production was partly compensated by production from the start-up of new fields and ramp-up on existing fields. Total entitlement production decreased by 6% from 2009 to 2010. It was impacted by the same factors as equity production and also by changes in profit tranches for some of our fields in Angola and higher prices leading to reduced entitlement shares on other fields.

The production cost per boe of entitlement volumes was NOK 48.4 for the 12 months ending 31 December 2011, compared with NOK 42.8 for the 12 months ending 31 December 2010. In 2009, the production cost per boe was NOK 38.4. Equity volumes represent produced volumes under PSA contracts that correspond to Statoil's ownership percentage in a specific field, while entitlement volumes represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions. Production costs are incurred on the basis of our equity production. The management therefore believes that unit of production cost based on equity production is a better measure of cost control than unit of production cost based on entitlement volumes.

Based on equity volumes, the production cost per boe for the 12 months ending 31 December 2011 and 2010 was NOK 43.1 and NOK 38.6, respectively. In 2009, the production cost per boe was NOK 35.3. Adjusted for restructuring costs, reversal of restructuring costs and other costs arising from the merger recorded in the fourth quarter 2007 and gas injection costs, the production cost per boe of equity production for the 12 months ending 31 December 2011 and 2010, was NOK 42.4 and NOK 37.9, respectively. The corresponding figure for 2009 was NOK 35.3.

Adjustments are made for certain costs relating to the purchase of gas used for injection into oil-producing reservoirs. The adjustment facilitates comparison of field production costs with other fields that do not pay for their own gas used for injection into oil-producing reservoirs.



The increase in **adjusted production cost per boe** from 2010 to 2011, is mainly related to higher costs from fields preparing for production start-up and entering the production ramp-up phase resulting in a relatively higher cost per boe from new fields coming on stream.

Net income from associated companies was NOK 1.3 billion in 2011, NOK 1.2 billion in 2010 and NOK 1.5 billion in 2009.

Other income was NOK 23.3 billion in 2011, compared to NOK 1.8 billion in 2010 and NOK 1.4 billion in 2009. The significant increase in other income from 2010 to 2011 stems mainly from gains on sale of assets primarily related to the reduction of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled on 2011. The increase in other income from 2009 to 2010 was mainly related to a gain on sale of assets and insurance proceeds relating to business interruptions.

Purchase [net of inventory variation] includes the cost of the liquids production purchased from the Norwegian State pursuant to the Owners Instruction. See section *Operational review - Applicable laws and regulations- SDFI oil & gas marketing & sale* for more details. The purchase, net of inventory variation amounted to NOK 319.6 billion in 2011, compared to NOK 257.4 billion in 2010 and NOK 205.9 billion in 2009. Both the 25% increase from 2009 to 2010 and the 24% increase from 2010 to 2011 were mainly caused by higher liquid prices measured in NOK.

Operating expenses and selling, general and administrative expenses include field production costs, costs incurred for transport systems related to the company's share of oil and natural gas production, expenses relating to the sale and marketing of our products, such as business development costs, payroll expenses and employee benefits.

In 2011, operating expenses and selling, general and administrative expenses amounted to NOK 73.6 billion, an increase of NOK 4.8 billion over 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.

In 2010, operating expenses and selling, general and administrative expenses amounted to NOK 68.8 billion, an increase of NOK 1.5 billion over 2009 when operating expenses were NOK 67.3 billion. The 2% increase was mainly attributable to higher operating costs related to preparation for start up on new fields, and a provision for an onerous contract in 2010. The increase was partly offset by lower transportation costs because of reduced production, cost reductions from cost saving activities and a reversal of a provision for an onerous contract relating to Cove Point terminal.

Depreciation, amortisation and net impairment losses includes depreciation of production installations and transport systems, depletion of fields in production, amortisation of intangible assets and depreciation of capitalised exploration expenditure. It also includes impairment of property, plant and equipment and reversals of impairments. These total expenses amounted to NOK 51.4 billion in 2011, compared with NOK 50.7 billion in 2010 and NOK 53.8 billion in 2009. Included in these totals were net impairment losses of NOK 2.0 billion for 2011, NOK 4.8 billion for 2010 and NOK 7.2 billion for 2009.

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, the impact on depreciation from revisions of removal and abandonment estimates. The increase was partly offset by the impact of lower production, increased reserve estimates and lower net impairment losses. The 6% decrease in depreciation, amortisation and net impairment losses in 2010 compared with 2009 was mainly due to lower impairment losses in 2010 and lower entitlement volumes.

Depreciation, amortisation and net impairment losses (in NOK billion)	2011	2010 (restated)	Year ended 31 December		
			2009 (restated)	11-10 change	10-09 change
Ordinary depreciation	50.1	45.7	46.4	10 %	(2 %)
Amortisation of intangible assets	0.1	0.2	0.1	(44 %)	40 %
Impairments	4.5	4.7	8.2	(5 %)	(43 %)
Reversal of impairments	(3.3)	0.1	(2.0)	<(100 %)	>(100 %)
Impairment of intangible assets	0.0	0.0	1.0	0 %	(100 %)
Depreciation, amortisation and net impairment losses	51.4	50.7	53.8	1 %	(6 %)

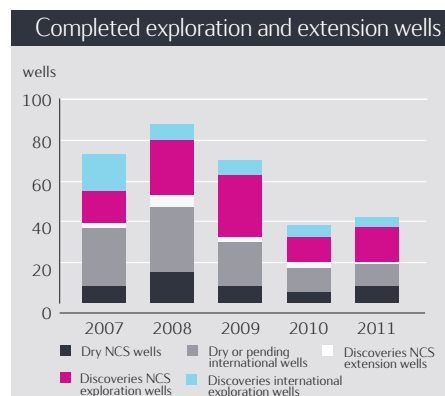
Exploration expenditures are capitalised to the extent that exploration efforts are considered successful, or pending such assessment. Otherwise, such expenditures are expensed.

Exploration Expenses (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		
			2009 (restated)	11-10 Change	10-09 Change
Exploration expenditure (activity)	18.8	16.8	16.9	12 %	(1%)
Expensed, previously capitalised exploration expenditure	1.8	2.6	1.6	(30 %)	66 %
Capitalised share of current periods exploration activity	(6.4)	(3.9)	(7.2)	64 %	(45%)
Impairment	1.6	1.9	5.4	(19 %)	(64%)
Reversal of impairment	(1.9)	(1.6)	0.0	14 %	0 %
Exploration Expenses	13.8	15.8	16.7	(12 %)	(5%)

The exploration expenses consist of the expensed portion of our exploration expenditure and impairment of exploration expenditure capitalised in previous years. In 2011, the exploration expenses were NOK 13.8 billion, a 12% decrease since 2010, when exploration expenses were NOK 15.8 billion. Exploration expenses were NOK 16.7 billion in 2009.

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. The 5% decrease in exploration expenses from 2009 to 2010 was mainly due to lower drilling activity and a smaller proportion of exploration expenditure capitalised in previous years being impaired. The decrease was partly offset by higher oil sands delineation drilling expenses, higher seismic expenditures and higher pre-sanctioning costs.

In 2011 Statoil completed 41 **exploration and appraisal wells**, 25 on the NCS and 16 internationally. A total of 22 wells were announced as discoveries in the period, 17 on the NCS and five internationally. In 2010, a total of 35 exploration and appraisal wells were completed, 17 on the NCS and 18 internationally. A total of 19 wells were announced as discoveries in the period, 12 on the NCS and seven internationally. In addition, four exploration extension wells were completed on the NCS in 2010, three of which were announced as discoveries. In 2009, a total of 68 exploration and appraisal wells and two exploration extension wells were completed, 41 on the NCS and 29 internationally. Thirty-eight exploration and appraisal wells and two exploration extension wells were declared as discoveries in the period.



Net operating income was NOK 211.8 billion in 2011, compared with NOK 137.3 billion in 2010 and NOK 121.7 billion in 2009.

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. The 13% increase from 2009 to 2010 was primarily attributable to higher prices for liquids, partly offset by lower gas prices, reduced volumes of liquids sold, and losses on derivatives.

In 2011, impairment losses net of reversals (NOK 0.9 billion), underlift and other adjustments, negatively impacted net operating income, while gain on sale of assets (NOK 22.6 billion), higher fair value of derivatives (NOK 12.0 billion), higher values of products in operational storage and reversal of an onerous contract related to the Cove Point Terminal provision (NOK 0.7 billion), had a positive impact on net operating income.

In 2010, net operating income was negatively affected by impairment losses net of reversals (NOK 4.8 billion), lower fair value of derivatives (NOK 2.9 billion) and a provision for an onerous contract relating to the Cove Point terminal in the USA (NOK 0.8 billion), while overlift and gain on the sale of assets (NOK 1.3 billion) had a positive impact on net operating income.

In 2009, net operating income was negatively affected by impairment losses net of reversals (NOK 12.2 billion) and underlift, while higher fair value of derivatives (NOK 2.2 billion), other accruals, gain on the sale of assets (NOK 0.5 billion) and reversals of restructuring costs (NOK 0.3 billion) all had a positive effect on net operating income in 2009.

Net financial items amounted to a gain of NOK 2.1 billion in 2011, compared with a loss of NOK 0.4 billion in 2010. The positive change of NOK 2.5 billion was mostly attributable to fair value changes on interest rate swap positions of NOK 4.3 billion, due to US dollar interest rates decreasing on average 1.3% in 2011, compared with US dollar interest rates decreasing on average 0.5% in 2010, partly offset by an increase in losses on financial investments of NOK 2.0 billion.

Net foreign exchange gains in 2011 were NOK 0.4 billion compared with net foreign exchange losses in 2010 of NOK 1.8 billion. The changes were mainly related to changes in currency derivatives used for currency and liquidity risk management, partly offset by currency effects on the working capital.

Interest income and other financial items amounted to NOK 1.3 billion in 2011, compared with NOK 3.1 billion in 2010. The NOK 1.8 billion decrease from 2010 to 2011 was related to a NOK 2.0 billion decrease in gains from financial investments, mainly on equities and commercial paper, in combination with a NOK 0.1 billion increase in interest income from financial investments, receivables and assets.

Interest and other finance expenses amounted to a net income of NOK 0.4 billion for 2011, compared with a net expense of NOK 1.7 billion for 2010. The change of NOK 2.1 billion was mostly due to fair value changes on interest rate swap positions relating to the interest rate management of non-current bonds. For 2011, fair value gains amounted to NOK 6.9 billion compared to fair value gains in 2010 of NOK 2.6 billion. The NOK 4.3 billion increase in 2011 is offset by increased finance expenses of NOK 1.4 billion mainly due to the Pernis impairment and the Heidrun redetermination in 2011.

In 2010, net financial items amounted to a loss of NOK 0.4 billion in 2010, compared with a loss of NOK 6.7 billion in 2009. The positive change of NOK 6.3 billion from 2009 to 2010 was mostly attributable to fair value changes on interest rate swap positions, due to decreasing US dollar interest rates in 2010, compared with increasing US dollar interest rates in combination with a 17% weakening of the US dollar in relation to NOK in 2009.

Net foreign exchange losses in 2010 of NOK 1.8 billion and net foreign exchange gains in 2009 of NOK 2.0 billion are mainly related to currency derivatives used for currency and liquidity risk management. They are partly offset by currency effects on the working capital.

Interest income and other financial items amounted to NOK 3.2 billion for 2010, compared with NOK 3.7 billion for 2009. The NOK 0.5 billion decrease was mainly related to a NOK 0.4 billion decrease in interest income on current financial assets in combination with a NOK 0.2 billion decrease in interest income on net financial investments.

Interest and other finance expenses amounted to a net expense of NOK 1.8 billion for 2010, compared with a net expense of NOK 12.5 billion for 2009. The decrease of NOK 10.7 billion was mostly due to fair value changes on interest rate swap positions relating to the interest rate management of external loans. For 2010, fair value gains amounted to NOK 2.6 billion. Correspondingly, fair value losses for 2009 amounted to NOK 6.6 billion.

Income taxes were NOK 135.4 billion in 2011, equivalent to an effective tax rate of 63.3%, compared with NOK 99.2 billion in 2010, equivalent to an effective tax rate of 72.5%, and NOK 97.2 billion in 2009, equivalent to an effective tax rate of 84.6%.

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 United States operations were recognised in 2011.

The decrease in the effective tax rate from 2009 to 2010 was mainly due to high taxes in 2009 caused by higher taxable income than accounting income in companies that are taxable in other currencies than the functional currency. The decrease in the effective tax rate was also caused by relatively lower income from the NCS in 2010 compared with 2009. Income from the NCS is subject to a higher than average tax rate.

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 components 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 2011, the **non-controlling interest** in net profit was NOK 0.3 billion, compared to NOK 0.4 billion in 2010 and NOK 0.6 billion in 2009. The non-controlling interest in 2011 is primarily related to Statoil's 54% ownership of Statoil Fuel & Retail, starting in October 2010, and the 79% ownership of Mongstad crude oil refinery.

Net income was NOK 78.4 billion in 2011, compared to NOK 37.6 billion in 2010 and NOK 17.7 billion in 2009.

The 108% increase from 2010 to 2011 was mainly due to the increased 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 112% increase from 2009 to 2010 was mainly due to increased net operating income as a result of higher revenues from liquids and a lower net financial loss, only partly offset by higher income taxes.

The board of directors will propose for approval at the annual general meeting an **ordinary dividend** of NOK 6.50 per share for 2011, 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. In 2009, the ordinary dividend was NOK 6.00 per share, an aggregate total of NOK 19.1 billion.

4.1.3 Group outlook

Equity production for 2012 is estimated to grow by around 3% compound annual growth rate (CAGR) based on the actual 2010 equity production. Organic capital expenditures for 2012 are estimated at around USD 17 billion.

Organic capital expenditures for 2012 (i.e. excluding acquisitions and capital leases), are estimated at around USD 17 billion, including expenditures relating to our new assets from the recent Brigham acquisition.

The company will continue to mature its large portfolio of exploration assets and expects to complete around 40 wells with a total **exploration activity** level in 2012 similar to the 2011 level for an expenditure around USD 3 billion, excluding signature bonuses.

Statoil has an ambition to continue to be in the top quartile of its peer group for **unit of production cost**.

Planned turnarounds are expected to have a negative impact on the quarterly production of liquids and gas of approximately 20 mboe per day in the first quarter of 2012, all of which are planned outside the NCS. In total, the turnarounds are estimated to have an impact on equity production of around 50 mboe per day for the full year 2012, of which most are liquids.

Equity production for 2012 is estimated to grow by around 3% compound annual growth rate (CAGR) based on the actual 2010 equity production. 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.

We expect prices for crude oil to continue to be volatile in the short to medium term, but at a relatively high level. Oil product prices will in general follow those of crude oil. Refining margins were low in 2011 due to overcapacity and competition for available crude oil cargoes. Refinery closures at the end of 2011 should lead to less overcapacity and slightly better margins in the near term. The refining industry is expected to still face major challenges in 2012. Even though global oil demand has recovered from 2009 levels, refinery overcapacity persists.

We believe that global oil demand will continue to increase moderately in 2012 and continue to grow at roughly the same pace over the next few years, as economic growth is expected to stay at moderate levels. The shift of higher oil consumption in emerging markets, and lower oil consumption in mature regions, is expected to continue. Emerging markets, led by China, are expected to increase usage of oil for industrial production, construction and transportation. Western Europe and the US are expected to see a fall in oil demand, primarily due to efficiency gains in the transportation sector and less intake from stationary facilities. Diesel demand in Europe is expected to be robust, but a surplus of European gasoline supply will need to be sold to other markets.

Supply of natural gas liquids (NGL) is expected to increase significantly, especially as supply associated with new US shale gas production reaches the market. European NGL production is likely to remain high as volumes associated with oil fields are replaced by NGL volumes from non-associated production. The increase in LPG availability is expected to find solid demand from the premium residential/heating segment, and as feedstock into the price-sensitive petrochemical industry. Naphtha is used in both the petrochemical and transportation sectors.

We continue to take a positive long-term view of gas as an energy source. Domestic production of gas in the EU continues to decline, while demand for gas is expected to increase in the long term, particularly due to the lower carbon footprint of natural gas compared with oil and coal. In the USA, the current increase in shale gas supply combined with a milder than normal winter has led us to expect relatively low gas prices in the short term. However, movement in exploration focus away from shale gas towards more shale liquids rich areas, together with an increase in new demand sources such as additional gas for power and, to a lesser extent, export markets via LNG, are expected to support prices in the medium to long term.

Statoil's income could vary significantly with changes in commodity prices, even if volumes remain stable through the year. There is a small seasonal effect on volumes in the winter and summer seasons due to normally higher off-takes of natural gas during cold periods. There is normally an additional small seasonal effect on volumes as a result of the higher maintenance activity level on offshore production facilities during the second and third quarters each year, since generally better weather conditions allow for more maintenance work.

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 *Forward-looking statements* section for more information.

4.1.4 Segment performance and analysis

Oil and natural gas are subject to internal transactions between our reporting segments before being sold in the market. We have established a pricing policy for transfers based on the estimated market price.

A new corporate structure was implemented from 1 January 2011. Prior periods have been restated to be comparable, see the *Consolidated financial statements - note 4 Segments* - for further information.

The table below details certain financial information for our five reporting segments: Development and Production Norway (DPN), Development and Production International (DPI), Marketing, Processing and Renewable Energy (MPR), Fuel & Retail (SFR) and Other. The Other reporting segment includes activities within Global Strategy and Business Development; Technology, Projects and Drilling; and Corporate Staffs and Services.

We eliminate intercompany sales when combining the results of reporting segments. These 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.

DPN in Statoil Petroleum AS produces oil and natural gas, which it sells internally to MPR in Statoil ASA. A large share of the oil produced by DPI is also sold from legal entities holding the relevant license to 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 2011, the average transfer price for natural gas per standard cubic metre was NOK 1.64 per scm. The average transfer price was NOK 1.27 per scm in 2010 and NOK 1.39 in 2009. 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.

For additional information please refer to the *Consolidated Financial Statements - note 4 Segments*.

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 2011.

(in NOK billion)	2011	For the year ended 31 December 2010 (restated)	2009 (restated)
Development & Production Norway			
Total revenues and other income	212.1	170.7	158.7
Net operating income	152.7	115.6	104.3
Other segment non-current assets*	211.6	188.2	176.0
Development & Production International			
Total revenues and other income	70.9	51.0	41.8
Net operating income	32.8	12.6	2.6
Other segment non-current assets*	239.4	137.3	152.7
Marketing, Processing and Renewable Energy			
Total revenues and other income	610.0	493.6	422.7
Net operating income	24.7	6.1	16.3
Other segment non-current assets*	34.4	55.2	53.6
Fuel & Retail			
Total revenues and other income	73.7	65.9	57.4
Net operating income	1.9	2.4	1.3
Other segment non-current assets*	10.8	11.1	11.8
Other and elimination			
Total revenues and other income	(296.5)	(251.3)	(215.2)
Net operating income	(0.4)	0.5	(2.8)
Other segment non-current assets*	4.0	3.0	2.8
Statoil group			
Total revenues and other income	670.2	529.9	465.4
Net operating income	211.8	137.3	121.6
Other segment non-current assets*	500.3	394.7	396.9

*Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

The following tables show total revenues by geographic area.

(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2011						
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

(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2010 (restated)						
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
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(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2009 (restated)						
Norway	182,353	80,018	34,655	45,927	18,375	361,328
USA	19,836	5,555	117	14,017	672	40,197
Sweden	0	0	0	16,556	3,795	20,351
Denmark	0	0	0	15,105	1,957	17,062
Other	9,978	2,959	154	10,762	1,102	24,955

Total revenues (excluding net income (loss) from associated companies)	212,167	88,532	34,926	102,367	25,901	463,893
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4.1.5 Development and Production Norway (DPN)

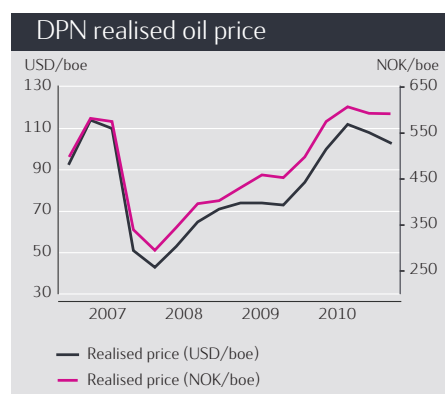
In 2011, Development and Production Norway delivered strong financial results and strong cash flows, despite reduced production.

Net operating income in 2011 was NOK 152.7 billion, compared with NOK 115.6 billion in 2010. Strategic portfolio optimisation in 2011 included the Centrica transaction which is expected to be closed in the second quarter of 2012, the increased ownership interests in Heidrun and Snøhvit and an active year maturing and sanctioning new projects. Our production of oil and gas on the NCS averaged 1,316 mboe per day in 2011, compared with 1,374 mboe per day in 2010 and 1,450 mboe per day in 2009.

4.1.5.1 DPN profit and loss analysis

DPN generated total revenues of NOK 212.1 billion in 2011 and its net operating income was NOK 152.7 billion. The average daily entitlement production was 693 mboe per day for liquids and 624 mboe per day for gas.

IFRS Income statement (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		
			2009 (restated)	11-10 change	10-09 change
Total revenues and other income	212.1	170.7	158.7	24 %	8%
Operating expenses and Selling, general and administrative expenses	24.7	23.6	23.5	5 %	0%
Depreciation, amortisation and net impairment losses	29.6	26.0	25.7	14 %	1%
Exploration expenses	5.1	5.5	5.2	(7 %)	6%
Total expenses	59.4	55.1	54.3	8 %	1%
Net operating income	152.7	115.6	104.3	32 %	11%
Operational data:					
Liquids price (USD/bbl)	105.6	76.3	57.8	39 %	32%
Liquids price (NOK/bbl)	592.3	461.0	363.0	28 %	27%
Transfer price natural gas (NOK/scm)	1.64	1.27	1.38	29 %	(8%)
Liftings:					
Liquids (mboe per day)	673	711	778	(5 %)	(9%)
Natural gas (mboe per day)	624	669	666	(7 %)	0%
Total liquids and gas liftings (mboe per day)	1,297	1,380	1,444	(6 %)	(4%)
Production:					
Entitlement liquids (mboe per day)	693	704	784	(2 %)	(10%)
Entitlement natural gas (mboe per day)	624	669	666	(7 %)	0%
Total entitlement liquids and gas production (mboe per day)	1,316	1,374	1,450	(4 %)	(5%)



Total revenues and other income were NOK 212.1 billion in 2011, NOK 170.7 billion in 2010 and NOK 158.7 billion in 2009. An increase of 39% in the average price in USD of oil sold by DPN to MPR accounted for NOK 43.8 billion of the increase in revenues, and an increased gas price in NOK of sold gas, also made a positive contribution of NOK 13.4 billion in 2011.

This was partly offset by a negative currency exchange rate deviation of NOK 11.5 billion due to a 7% decrease in the USD/NOK exchange rate in 2011. Furthermore, a 5% decrease in lifted volumes of liquids accounted for NOK 5.2 billion of the decrease in revenues and a 7% decrease in lifted volumes of gas accounted for NOK 3.4 billion of the decrease in revenues.

There was an increase in total revenues and other income from NOK 158.7 billion in 2009 to NOK 170.7 billion in 2010. An increase of 32% in the average price in USD of oil sold by DPN to MPR accounted for NOK 29.3 billion of the increase in revenues, and a minor increase in lifted volumes of natural gas, also made a positive contribution of NOK 0.2 billion. This was partly offset by a decrease of 9% in lifted volumes of liquids, making a negative contribution of NOK 8.9 billion and a negative

currency exchange rate deviation of NOK 4.7 billion due to a 4% increase in the USD/NOK exchange rate in 2010. Furthermore, an 8% decrease in the average transfer price in NOK of natural gas sold by DPN to MPR reduced revenues by NOK 4.1 billion.

The average daily lifting of liquids in 2011 was 673 mboe per day, compared with 711 mboe per day in 2010 and 778 mboe per day in 2009. Over time, the volumes lifted and sold will equal the volumes produced, but they may be higher or lower in any period due to differences between the capacity of the

vessels lifting our volumes and the actual entitlement production in the period, see section *Definitions of reported volumes* for more information. The average daily underlift was 19 mboe per day in 2011 compared with an average overlift of 6 mboe overlift per day in 2010 and an average underlift of 6 mboe per day in 2009.

The average daily production of entitlement liquids in 2011 was 693 mboe per day, compared with 704 mboe per day in 2010 and 784 mboe per day in 2009. The decrease in liquids production is 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.

The decrease in production from 2009 to 2010 was mainly related to the Gullfaks C-06 well control incident in May 2010, Operations West water injection issues and a decline in the main field on Gullfaks, reduced capacity at Kollsnes, a lower production permit than expected on Ormen Lange and operational challenges on Kristin and Oseberg. The negative effect on average daily production was approximately 70 mbbl in 2010. In addition, we had expected production profile reductions due to a natural decline on mature fields. The decrease was partly offset by increased production at Morvin and Tyrihans.

The average daily production of entitlement gas was 624 mboe per day in 2011 compared with 669 mboe in 2010 and 666 mboe in 2009.

Operating expenses and selling, general and administrative expenses were NOK 24.7 billion in 2011, compared with NOK 23.6 billion in 2010 and NOK 23.5 billion in 2009. In 2011, expenses increased mainly due 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. The increase of NOK 0.1 billion from 2009 to 2010 was due to increased operating plant costs and other expenses, partly offset by a decrease in transportation costs due to lower lifting of liquids.

Depreciation, amortisation and net impairment losses were NOK 29.6 billion in 2011, compared with NOK 26.0 billion in 2010 and NOK 25.7 billion in 2009. The increase in 2011 compared with 2010 is 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. The NOK 0.3 billion increase from 2009 to 2010 was mainly related to increased investments on mature fields, partly offset by a change in the producing fields portfolio.

Depreciation, amortisation and net impairment losses (in NOK billion)	2011	For the year ended 31 December			10-09 Change
		2010 (restated)	2009 (restated)	11-10 Change	
Ordinary depreciation	29.6	25.9	25.5	14 %	2 %
Amortisation of intangible assets	0.0	0.0	0.0	0 %	0 %
Impairments	0.0	0.1	0.1	(100 %)	(27%)
Depreciation, amortisation and net impairment losses	29.6	26.0	25.7	14 %	1 %

Exploration expenditure (including capitalised exploration expenditure) in 2011 amounted to NOK 6.6 billion, compared with NOK 6.0 billion in 2010 and NOK 8.2 billion in 2009. The increase from 2010 to 2011 was mainly due to a higher number of wells being drilled in 2011, as well as a higher average Statoil share per well, compared to 2010. Seismic costs were higher in 2011 due to increased regional focus in the Barents and Norwegian Sea, related to surveys for the 22nd concession round and the purchase of Norwegian Petroleum Directorate (NPD) seismic in Nordland 7. The decrease in exploration expenditure from 2009 to 2010 was mainly due to lower activity and fewer wells being drilled in 2010.

Exploration expenses in 2011 were NOK 5.1 billion, compared with NOK 5.5 billion in 2010 and NOK 5.2 billion in 2009.

In 2011, 25 exploration and appraisal wells and four exploration extension wells were completed on the NCS, of which 17 exploration and appraisal wells and one exploration extension well were announced as discoveries.

In 2010, 17 exploration and appraisal wells and four exploration extension wells were completed on the NCS, of which 12 exploration and appraisal wells and three of the exploration extension wells were announced as discoveries. Higher exploration expenditure due to higher drilling activity in 2011 have been offset by increased capitalised exploration costs as more discoveries have been made in 2011.

In 2009, 39 exploration and appraisal wells and two exploration extension wells were completed on the NCS, of which 31 exploration and appraisal wells and both of the exploration extension wells were announced as discoveries.

The drilling of four exploration and appraisal wells was ongoing at the end of 2011. The reconciliation of exploration expenditure with exploration expenses is shown in the table below.

Exploration Expenses (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		10-09 Change
			2009 (restated)	11-10 Change	
Exploration expenditure (activity)	6.6	6.0	8.2	10 %	(27%)
Expensed, previously capitalised exploration expenditure	1.1	1.4	1.2	(26 %)	22 %
Capitalised share of current periods exploration activity	(2.5)	(1.9)	(4.2)	31 %	(54%)
Impairment	0.0	0.0	0.0	0 %	0 %
Reversal of impairment	0.0	0.0	0.0	0 %	0 %
Exploration Expenses	5.1	5.5	5.2	(7 %)	6 %

Net operating income in 2011 was NOK 152.7 billion, compared with NOK 115.6 billion in 2010 and NOK 104.3 billion in 2009. The NOK 37.1 billion increase in 2011 was mainly due to increased liquid prices. The NOK 11.3 billion increase in 2010 was mainly due to increased liquid prices.

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. Underlift, a change in future settlement related to a sale of a license 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 in 2010, partly offset by a refund of historic gas purchase (NOK 0.1 billion) that negatively impacted net operating income 2010.

In 2009, an unrealised gain on derivatives (NOK 1.5 billion), a change in future settlement related to a sale of a licence share (NOK 0.5 billion), restructuring costs (NOK 0.3 billion) and a refund of a historic gas purchase (NOK 0.3 billion) had a positive impact on net operating income 2009, while underlift (NOK 0.8 billion) and provision for a take-or-pay contract (NOK 0.2 billion) had a negative impact on net operating income.

4.1.6 Development and Production International (DPI)

In 2011, Development and Production International delivered strong financial results and entitlement volumes on par with 2010.

Net operating income in 2011 was NOK 32.8 billion, compared with NOK 12.6 billion in 2010. Strategic portfolio optimisation in 2011 mainly included the 40% divestment of ownership interests in Peregrino in Brazil and Kai Kos Dehseh oil sands in Canada. DPI's entitlement production of oil and gas averaged 334 mboe per day in 2011, compared with 332 mboe per day in 2010 and 357 mboe per day in 2009. The average daily equity production of liquids and gas was 534 mboe per day in 2011, compared with 514 mboe per day in 2010 and 512 mboe per day in 2009.

Equity volumes represent produced volumes corresponding to Statoil's percentage of ownership in a particular field. Entitlement volumes represent Statoil's share of the volumes distributed to the partners in the field. Under a production sharing agreement (PSA) entitlement volumes are subject to deductions for, among other things, royalties and the host government's share of profit oil. Entitlement volumes lifted are the basis for revenue recognition, while equity production volumes affect operating costs more directly. 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 license. The distinction between equity and entitlement is relevant to most PSA regimes. The main countries in which Statoil operates under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Our international portfolio has been further strengthened in 2011 through the acquisition of more than 375,000 acres in the Bakken and Three Forks tight oil plays in the Williston Basin in North Dakota and Montana in the US on 1 December 2011 through the acquisition of Brigham Exploration Company. In addition, Statoil acquired additional acreage in the Marcellus shale gas and Eagle Ford shale oil plays in the US during 2011. An overview of portfolio transactions in 2011 is presented in the section *Operational review - Development and Production International - The DPI portfolio*.

In total, 16 exploration and appraisal wells were completed in 2011 and five wells were announced as discoveries. At year end, six wells were pending final evaluation. The total exploration expenses were NOK 8.7 billion in 2011, compared with NOK 10.3 billion in 2010.

4.1.6.1 DPI profit and loss analysis

In 2011, DPI generated total revenues and other income of NOK 70.9 billion and a net operating income of NOK 32.8 billion. The average daily entitlement production of liquids was 252 mboe per day.

IFRS income statement (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		10-09 change
			2009 (restated)	11-10 change	
Total revenues and other income	70.9	51.0	41.8	39 %	22%
Purchase [net of inventory variation]	0.7	0.0	1.1	>100 %	(98%)
Operating expense and Selling, general and administrative expenses	14.9	11.4	9.5	30 %	20%
Depreciation, amortisation and net impairment losses	13.8	16.7	17.1	(17 %)	(3%)
Exploration expenses	8.7	10.3	11.5	(15 %)	(11%)
Total expenses	38.1	38.4	39.2	(1 %)	(2%)
Net operating income	32.8	12.6	2.6	>100 %	>100%
Operational data:					
Liquids price (USD/bbl)	105.7	76.8	58.4	38 %	32%
Liquids price (NOK/bbl)	592.8	464.2	366.5	28 %	27%
Liftings:					
Liquids (mboe per day)	237	258	267	(8 %)	(3%)
Natural gas (mboe per day)	82	68	74	20 %	(8%)
Total liquids and gas liftings (mboe per day)	318	327	341	(2 %)	(4%)
Production:					
Entitlement liquids (mboe per day)	252	263	283	(4 %)	(7%)
Entitlement natural gas (mboe per day)	82	68	74	20 %	(8%)
Total entitlement liquids and gas production (mboe per day)	334	332	357	1 %	(7%)
Total equity liquids and gas production (mboe per day)	534	514	512	4 %	0%

DPI generated **total revenues and other income** of NOK 70.9 billion in 2011 compared with NOK 51.0 billion in 2010 and NOK 41.8 billion in 2009. The increase from 2010 to 2011 was mainly related to a gain 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, with a positive contribution of NOK 12.5 billion. The increase was partly offset by a 2% reduction in lifted volumes, which contributed negatively in the amount of NOK 3.0 billion and a net reduction in other income of NOK 3.8 billion.

The increase from 2009 to 2010 was mainly related to a 25% increase in realised liquid and gas prices that made a positive contribution of NOK 9.4 billion and a 63% increase in other income that made a positive contribution of NOK 1.2 billion. The increase was partly offset by a 4% reduction in lifted volumes, which contributed negatively in the amount of NOK 1.4 billion.

The **average daily lifting of liquids** was 237 mboe per day in 2011, compared with 258 mboe per day in 2010 and 267 mboe per day in 2009. Over time, the volumes lifted and sold will equal our production of entitlement volumes, 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 *Definition of reported* volumes for more information. The average daily over/underlift in 2011, 2010 and 2009 was 1 mboe per day in overlift, 8 mboe per day in overlift and 2 mboe per day in underlift, respectively.

The **average daily entitlement production of liquids** was 252 mboe per day in 2011, compared with 263 mboe per day in 2010 and 283 mboe per day in 2009. The 4% decrease in average daily liquids entitlement production from 2010 to 2011 was mainly related to a higher PSA effect due to changes in profit tranches and higher prices leading to reduced entitlement shares, turnaround on Azeri, Chirag & Gunashli (ACG) in Azerbaijan and decline in production profiles in several fields in Angola. The decrease was partly offset by start-up of Peregrino in Brazil and Pazflor in Angola. The 7% decrease in average daily liquids entitlement production from 2009 to 2010 was mainly related to a higher PSA effect due to changes in profit tranches and higher prices leading to reduced entitlement shares, a decline in production profile and operational issues in several fields in Angola, and a reduced ownership share in the Mabruk field in Libya.

The average daily entitlement production of gas was 82 mboe per day in 2011 (equivalent to 13 mmcm or 460 mmcf per day), compared with 68 mboe per day in 2010 (equivalent to 11 mmcm or 384 mmcf per day) and 74 mboe in 2009 (equivalent to 12 mmcm or 413 mmcf per day). The increase in daily gas production from 2010 to 2011 was mainly related to U.S. onshore production at Marcellus with an increased number of wells online and at Eagle Ford which was acquired in December 2010. The decrease in daily gas production from 2009 to 2010 was mainly related to a decline in mature fields in the Independence Hub in the US Gulf of Mexico.

The average daily equity liquids and gas production was 534 mboe in 2011, compared with 514 mboe in 2010 and 512 mboe in 2009.

Purchase [net of inventory variation] was NOK 0.7 billion in 2011, compared with NOK 0.0 billion in 2010 and NOK 1.1 billion in 2009. The increase from 2010 to 2011 was mainly related to diluent purchases for Leismer operations that started in January 2011.

Operating expenses and selling, general and administrative expenses were NOK 14.9 billion in 2011, compared with NOK 11.4 billion in 2010 and NOK 9.5 billion in 2009. The 30% increase from 2010 to 2011 is mainly due to ramp-up of Marcellus and Eagle Ford in the U.S and production start-up of Peregrino in Brazil, Pazflor in Angola and Leismer in Canada in 2011. In addition, royalty payments on Tahiti increased expenses in 2011. The 20% increase from 2009 to 2010 is mainly due to increased preparation for operations on the Peregrino field in Brazil.

Depreciation, amortisation and net impairment losses were NOK 13.8 billion in 2011, compared with NOK 16.7 billion in 2010 and NOK 17.1 billion in 2009. The 17% 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 U.S 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. The 3% decrease from 2009 to 2010 was mainly due to decreased depreciation as proved reserves increased in 2010, partly offset by increased net impairments.

Depreciation, amortisation and net impairment losses (in NOK billion)	2011	2010 (restated)	For the year ended 31 December 2009 (restated)	11-10 Change	10-09 Change
Ordinary depreciation	15.9	15.2	16.2	5 %	(6%)
Amortisation of intangible assets	0.0	0.0	0.0	(10 %)	(41%)
Impairments	0.3	1.6	2.6	(78 %)	(40%)
Reversal of impairments	(2.4)	(0.1)	(1.7)	>100 %	(95%)
Depreciation, amortisation and net impairment losses	13.8	16.7	17.1	(17 %)	(3%)

Exploration expenditure was NOK 12.2 billion in 2011, compared with NOK 10.8 billion in 2010 and NOK 8.7 billion in 2009. The increase from 2010 to 2011 was mainly due to higher drilling costs. Slightly lower drilling activity in 2011 was offset by more expensive wells in Brazil and Indonesia. Seismic expenditures increased due to high seismic activity in 2011. The increase from 2009 to 2010 was mainly due to increased exploration drilling costs and higher oil sands delineation drilling, increased higher seismic expenditures and higher pre-sanctioning costs.

Exploration expenses were NOK 8.7 billion in 2011, compared with NOK 10.3 billion in 2010 and NOK 11.5 billion in 2009. Despite increased drilling costs in 2011, exploration expenses decreased, primarily due to increased capitalisation of exploration expenditures in 2011 compared to 2010. The reduction from 2009 to 2010 was mainly due to a reduction in the amount of previously capitalized exploration expenditure that was expensed, which was partly offset by more oil sands delineation drilling, higher seismic expenditures and higher pre-sanctioning costs.

Exploration Expenses (in NOK billion)	2011	2010 (restated)	For the year ended 31 December 2009 (restated)	11-10 Change	10-09 Change
Exploration expenditure (activity)	12.2	10.8	8.7	13 %	24 %
Expensed, previously capitalised exploration expenditure	0.8	1.2	0.4	(35 %)	>100 %
Capitalised share of current periods exploration activity	(3.9)	(2.0)	(3.0)	95 %	(34%)
Impairment	1.6	1.9	5.4	(19 %)	(64%)
Reversal of impairment	(1.9)	(1.6)	0.0	14 %	0 %
Exploration Expenses	8.7	10.3	11.5	(15 %)	(11%)

In total, 16 exploration and appraisal wells were completed in 2011 and five wells were announced as discoveries. In 2010, 18 exploration and appraisal wells were completed and six wells were announced as discoveries. In 2009, 29 exploration and appraisal wells were completed and seven wells were announced as discoveries.

Net operating income in 2011 was NOK 32.8 billion, compared with NOK 12.6 billion in 2010 and NOK 2.6 billion in 2009. 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. The increase from 2009 to 2010 was mainly related to increased liquids prices.

In 2011 impairment reversals of NOK 2.4 billion positively impacted net operating income whereas an underlift negatively impacted net operating income.

4.1.7 Marketing, Processing and Renewable Energy (MPR)

In 2011, MPR experienced higher European gas prices and margins, and good operational performance in the production facilities. Lower margins from trading of liquids, storage strategies and refining partly offset the increase.

Gas prices developed positively in 2011 compared to 2010. Our volume-weighted average sales price was NOK 2.08 per scm in 2011 and NOK 1.72 per scm in 2010, an increase of approximately 21%. The volume-weighted average sales price was NOK 1.90 per scm in 2009.

The majority of our long-term gas supply contracts in Europe are indexed to oil products, which means that a change in oil prices affects the realized gas prices of these supply contracts after a certain time delay (typically 6-9 months). Oil prices increased, and this positively affected the development of natural gas prices. In addition, the gas indexed prices increased in 2011.

All of Statoil's gas produced on the NCS is sold by MPR, purchased from DPN at a market-based internal price. The gradually increasing natural gas sales prices in 2011 were largely offset by an increase in the internal purchase price. Our average internal purchase price for gas was NOK 1.64 per scm in 2011, up from NOK 1.27 per scm in 2010, an increase of 29%. The average internal purchase price for gas was NOK 1.38 per scm in 2009.

Natural gas sales volumes in 2011 were 50.4 bcm, compared to 52.8 bcm in 2010, a decrease of 5% mainly related to lower entitlement production in 2011. Natural gas volumes in 2009 were 49.8 bcm. Statoil sold 39.0 bcm of entitlement gas in 2011 compared to 41.7 bcm in 2010 and 41.4 bcm in 2009. In addition, we sold 33.5 bcm of NCS gas on behalf of the Norwegian State's direct financial interest (SDFI). Most of the gas was sold to European energy providers under long-term contracts.

Sales of third party volumes of natural gas amounted to 11.4 bcm in 2011, compared to 11.1 bcm in 2010, an increase of 3%. The increase was mainly due to optimisation and balancing of our portfolio. The sales of third party volumes of natural gas amounted to 8.4 bcm in 2009.

With an average of crude, condensate and NGL sales of 2.3 mmbbl per day in 2011, we are one of the world's largest net sellers of such products. Of these daily sales, approximately 0.96 mmbbl are sales of our own volumes, 0.91 mmbbl are sales of third party volumes and 0.45 mmbbl are sales of SDFI volumes. Our average sales volume was 2.3 mmbbl per day in 2010 and 2.4 mmbbl per day in 2009. The average daily third-party volumes sold in 2011 were 0.91 mmbbl, compared to 0.84 mmbbl in 2010 and 0.70 mmbbl in 2009.

Refinery throughput in 2011 was higher than in 2010 due to a higher on stream factor in 2011 and turnaround in 2010 at the Mongstad refinery. This was partly offset by the Kalundborg refinery, which had a lower on stream factor in 2011 compared to 2010, due to larger turnaround in 2011. The methanol production in 2011 was 8% higher than in 2010, mainly due to turnaround in 2010.

The refining industry continued to face major challenges in 2011. Even though global oil demand was high, refinery overcapacity was still present. The overcapacity is particularly challenging in the Atlantic Basin (countries accessible for shipment on the Atlantic Ocean), where some refineries decided to close operations permanently or temporary during 2010 and 2011. The refining reference margin was 2.3 USD/bbl in 2011 compared to 3.9 USD/bbl in 2010, a reduction of approximately 42% due to overcapacity in the market. The refining reference margin was 3.0 USD/bbl in 2009.

The Sheringham Shoal offshore wind farm in the UK where Statoil has an ownership interest started electricity production from the first wind turbines in August 2011. The major parts of Statoil's onshore wind power activities in Norway were sold during 2011.

4.1.7.1 MPR profit and loss analysis

For Marketing, Processing and Renewable Energy, net operating income increased from NOK 6.1 billion in 2010 to NOK 24.7 billion in 2011.

IFRS Income statement (in NOK billion)	For the year ended 31 December				
	2011	2010 (restated)	2009 (restated)	11-10 change	10-09 change
Total revenues and other income	610.0	493.6	422.7	24 %	17 %
Purchase [net of inventory variation]	550.5	452.1	370.2	22 %	22 %
Operating expenses and selling, general and administrative expenses	28.8	29.3	27.1	(2 %)	8 %
Depreciation, amortisation and net impairment losses	6.0	6.0	9.2	(0 %)	(34%)
Total expenses	585.2	487.5	406.4	20 %	20 %
Net operating income	24.7	6.1	16.3	>100 %	(62%)
Operational data:					
Refining reference margin (USD/bbl)	2.3	3.9	3.0	(41 %)	30 %
Contract price methanol (EUR/tonne)	308	254	173	21 %	47 %
Operational data:					
Natural gas sales Statoil entitlement (bcm)	39.0	41.7	41.4	(7 %)	1 %
Natural gas sales (third-party volumes) (bcm)	11.4	11.1	8.4	3 %	33 %
Natural gas sales (bcm)	50.4	52.8	49.7	(5 %)	6 %
Natural gas sales on commission	1.3	1.5	1.3	(11 %)	12 %
Natural gas price (NOK/scm)	2.08	1.72	1.90	21 %	(10%)
Transfer price natural gas (NOK/scm)	1.64	1.27	1.38	29 %	(8%)
Regularity at delivery point	100%	100%	100.0 %	0 %	0 %

The previously reported FCC refining margin has been replaced by a new refining reference margin. The refining reference margin is a typical, average gross margin of our two refineries, Mongstad and Kalundborg, and therefore has a higher correlation with our actual margins.

Total revenues and other income were NOK 610.0 billion in 2011, compared to NOK 493.6 billion in 2010 and NOK 422.7 billion in 2009. The increase in total revenues and other income 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, but this was partly offset by a weakening of the average USD/NOK exchange rate by almost 7%. The volume-weighted average 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.

The increase from 2009 to 2010 was mainly due to higher prices for crude and other oil products, partly offset by 10% lower volume-weighted average sales price for natural gas. Total natural gas sales volumes increased by 6% mainly due to increased third party volumes. The average crude price in USD increased by approximately 29% in 2010 compared to 2009, but this was partly offset by a weakening of the average USD/NOK exchange rate by almost 4%.

Purchase [net of inventory variation] was NOK 550.5 billion in 2011, compared to NOK 452.1 billion in 2010 and NOK 370.2 billion in 2009. The increase from 2010 to 2011 was mainly due to higher prices for volumes purchased, partly offset by a weakening of the average USD/NOK exchange rate. The increase from 2009 to 2010 was mainly due to higher prices for liquids purchased, partly offset by a lower transfer price for natural gas from DPN.

Operating expenses and selling, general and administration expenses were NOK 28.8 billion in 2011, compared to NOK 29.3 billion in 2010 and NOK 27.1 billion in 2009. 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. The increase in expenses from 2009 to 2010 was mainly related to the onerous contract provision at Cove Point in 2010 and due to the reversal in 2009 of a 2008 provision of NOK 1.3 billion relating to a take-or-pay contract.

Depreciation, amortisation and net impairment losses were NOK 6.0 billion in 2011, compared to NOK 6.0 billion in 2010 and NOK 9.2 billion in 2009. In 2011 we had higher impairment losses related to refinery assets, an impairment loss related to a gas fired power station and increased depreciation on new Mongstad refinery units, offset by reversal of an impairment loss in connection with Cove Point and lower depreciation driven by the Gassled divestment. The impairment of refinery assets reflects lower refinery margins due to continued overcapacity in the market. Determining recoverable value is sensitive to changes in refinery margins and exchange rates, and subsequent changes in these factors could result in additional impairment changes. The decrease in 2010 was mainly due to higher impairment losses related to refinery assets and intangible assets related to Cove Point in 2009.

Depreciation, amortisation and net impairment losses (in NOK billion)	2011	2010 (restated)	Year ended 31 December 2009 (restated)	11-10 change	10-09 change
Ordinary depreciation	2.7	3.0	2.9	(10 %)	2 %
Amortisation of intangible assets	0.1	0.0	0.1	>100 %	(93 %)
Impairments	4.1	3.0	6.2	37 %	(51 %)
Reversal of impairments	(8.7)	0.0	0.0	0 %	0 %
Depreciation, amortisation and net impairment losses	6.0	6.0	9.2	(0 %)	(34 %)

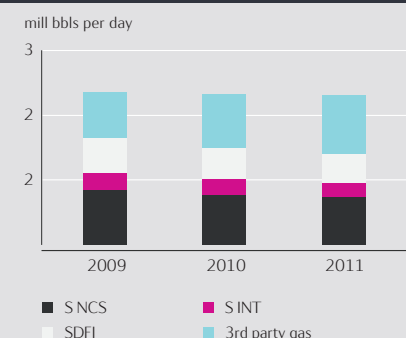
In 2011, the **net operating income** was NOK 24.7 billion, compared to NOK 6.1 billion in 2010 and NOK 16.3 billion in 2009. The net operating income in 2011 was positively impacted by a gain related to the sale of the 24.1% interest in Gassled (NOK 8.4 billion), a positive change in fair value of derivatives (NOK 4.6 billion), a gain due to periodisation of inventory hedging effects (NOK 2.3 billion), a reversal of a provision and an impairment in connection with Cove Point (NOK 1.6 billion), a gain on operational storage, higher margins on marketing and trading of gas, and a net gain on sale of wind assets (NOK 0.1 billion). Negative effects on net operating income in 2011 were impairment losses related to refinery assets and a gas fired power station (NOK 3.8 billion and NOK 0.3 billion, respectively), weaker trading results for crude oil, products and gas liquids, a decrease in volumes of gas sold, and lower refining margins.

Net operating income in 2010 was positively impacted by a gain on operational storage, and higher refining margins and methanol prices. Negative effects on net operating income in 2010 were a negative change in fair value of derivatives (NOK 4.1 billion), an impairment loss on a refinery asset (NOK 2.9 billion), a decrease of 10% in the volume-weighted average sales price reducing the marketing and trading margins, loss due to periodisation of inventory hedging effects (NOK 1.0 billion), a provision for an onerous contract in connection with Cove Point (NOK 0.9 billion), lower contribution from our processing and transport operations, a loss related to an onerous sales contract (NOK 0.4 billion), weaker results in liquids trading and turnarounds at the Mongstad and Kalundborg refineries.

Net operating income in 2009 was positively impacted by a gain due to a positive change in fair value of derivatives (NOK 2.7 billion), gain from a price change for our operational storage, a reversal of a take-or-pay contract provision (NOK 1.3 billion), strong marketing and trading margins both for natural gas and crude. Negative effects on net operating income in 2009 were an impairment loss on refinery assets (NOK 5.4 billion), a loss on inventory hedge positions that do not qualify for hedge accounting (NOK 2.0 billion), and low refining margins and methanol prices.

MPR consists of three product areas: **Natural Gas processing and transportation**, **Natural Gas marketing and trading** and **Crude Oil processing, marketing and trading**. Natural Gas processing and transport activities mainly consist of our share in Gassled. Natural Gas marketing and trading activities consist of our gas sales and trading activities, including the transportation costs associated with the Natural Gas activity. Crude Oil processing, marketing and trading activities mainly consist of our oil sales and trading activities in addition to our refinery activities, the Tjeldbergodden Methanol plant and our three crude oil terminals.

Traded volumes per day of oil



Net operating income in **Natural Gas processing and transportation** was NOK 13.5 billion in 2011, compared to NOK 5.5 billion in 2010. The increase was due to the gain related to the sale of the 24.1% interest in Gassled and reduced depreciation related to the Gassled interest sold, partly offset by reduced tariffs in Gassled and the 3.7% reduction in ownership share in Gassled with effect from 1 January 2011.

Net operating income in Natural Gas processing and transportation amounted to NOK 5.5 billion in 2010, compared to NOK 7.3 billion in 2009. The reduction was due to reduced income from Gassled, mainly due to a closure of a compressor at Kårstø, some regularity problems at Kårstø and Kollsnes, and production maintenance work during the third quarter of 2010.

Net operating income in Natural Gas processing and transportation is expected to be significantly lower in 2012 than 2011 due to the sale of the 24.1% interest in Gassled, in particular the NOK 8.4 billion gain in 2011 and Statoil's reduced ownership interest to 5% after the sale.

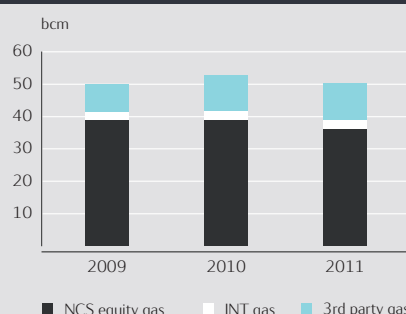
Sales price and transfer price



Net operating income in **Natural Gas marketing and trading** was NOK 14.0 billion in 2011, compared to NOK 2.8 billion in 2010. The increase was mainly due to 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 increase was partly offset by lower entitlement volumes and impairment loss in 2011 related to a gas-fired power station (NOK 0.3 billion).

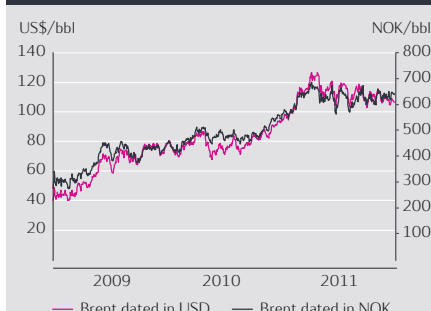
Net operating income in Natural Gas marketing and trading in 2010 was NOK 2.8 billion, compared to NOK 10.9 billion in 2009. The decrease was largely due to a large negative change in derivatives (negative NOK 4.1 billion in 2010, compared to positive NOK 2.7 billion in 2009). In addition, a positive volume deviation in 2010 compared to 2009 was more than offset by a negative margin deviation due to decreased sales prices and a lower contribution from trading. A decreased provision relating to an onerous contract (NOK 0.9 billion in 2010, compared to NOK 1.0 billion in 2009) partly offset the decreased net operating income.

Natural gas sales

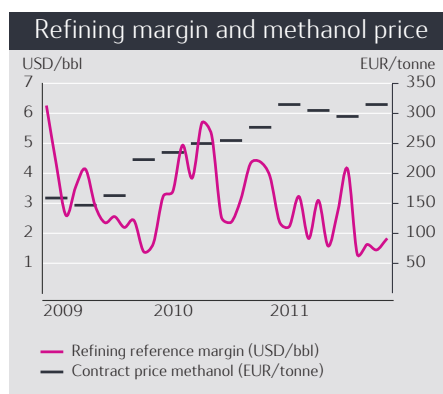


Total natural gas sales volumes were 50.4 bcm in 2011 (1.78 tcf), 52.8 bcm (1.87 tcf) in 2010 and 49.7 bcm (1.76 tcf) in 2009. The 5% decrease in total gas volumes sold from 2010 to 2011 was mainly related to lower entitlement production in 2011. The 6% increase in gas volumes sold from 2009 to 2010 was mainly due to increased third party volumes.

Brent dated in USD and NOK



In 2011, the **volume-weighted average sales price** for gas was NOK 2.08 per scm, compared to NOK 1.72 per scm in 2010, an increase of 21%. The increase was due to an increase in gas price for contracts linked to oil products as well as gas indexed prices. The volume-weighted average sales price was NOK 1.90 per scm in 2009. The decrease of 9% was mainly due to extraordinarily high prices in the first quarter 2009 as a result of the peak in oil product prices in 2008.



Net operating income in **Crude Oil processing, marketing and trading** was a loss of NOK 2.4 billion in 2011, compared to a loss of NOK 1.6 billion in 2010. The increased loss in 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 periodisation of inventory hedging effects (a gain of NOK 2.3 billion in 2011 compared to a loss of NOK 1.0 billion in 2010), 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.

Net operating income in Crude Oil processing, marketing and trading in 2010 was a loss of NOK 1.6 billion compared to a loss of NOK 1.4 billion in 2009. The increased loss was mainly due a lower gain on operational storage in 2010 compared to in 2009, reversal of a take-or-pay contract accrual in 2009 (NOK 1.3 billion), a loss related to an onerous contract regarding a sales contract (NOK 0.4 billion), and weaker trading results. The weaker trading results were mainly due to lower gains from

storage strategies under prevailing market conditions, with a flattened contango price structure, and losses due to the price drop in May 2010. The negative changes were partly offset by lower impairment losses on our refinery assets (NOK 2.9 billion in 2010, compared to NOK 5.4 billion in 2009), a positive change in periodisation of inventory hedging effects (a loss of NOK 1.0 billion in 2010 compared to a loss of NOK 2.0 billion in 2009), increased average refining margin and increased contract price for methanol.

4.1.8 Fuel & Retail (SFR)

Net operating income was NOK 1.9 billion in 2011, a decrease of 21% compared to 2010.

The decreased in net operating income was primarily explained by gain of NOK 0.3 billion from the sale of Swedegas in 2010 and the difficult market conditions in central and eastern Europe in 2011.

4.1.8.1 SFR profit and loss analysis

Total SFR revenue and other income increased from NOK 65.9 billion in 2010 to NOK 73.7 billion in 2011, driven by higher underlying refined oil products prices.

Income statement (in NOK billion)	2011	2010 (restated)	Twelve months ended 31 December		10-09 change
			2009 (restated)	11-10 change	
Total revenues and other income	73.7	65.9	57.4	12 %	15 %
Purchase [net of inventory variation]	63.6	54.8	46.9	16 %	17 %
Operating Expenses and Selling, general and administrative expenses	7.1	7.4	8.0	(5 %)	(8 %)
Depreciation, amortisation and net impairment losses	1.2	1.3	1.2	(11 %)	8 %
Total expenses	71.8	63.5	56.1	13 %	13 %
Net operating income	1.9	2.4	1.3	(21 %)	86 %

At the end of 2011, Statoil's ownership interest in Statoil Fuel & Retail ASA was 54%.

Total revenue and other income increased from NOK 65.9 billion in 2010 to NOK 73.7 billion in 2011, driven by higher underlying refined oil products prices.

Road transportation fuel volumes for the full year were 8.4 billion liters down by 0.1 billion liters compared with 2010. In addition, convenience revenues increased by NOK 0.5 billion in 2011 due to increased basket size, favourable initiatives within the food line and car wash areas, as well as increased duties

for tobacco. Total revenue and other income in the aviation and lubricants business increased by NOK 0.25 billion and NOK 1.1 billion respectively, due to increased underlying refined oil product prices in 2011 compared with 2010.

Total revenues and other income increased from NOK 57.4 billion in 2009 to NOK 65.9 billion in 2010. The increase was mainly driven by higher underlying refined oil product prices and increased road transportation fuel volumes of 5.9%. The increase in road transportation fuel volume was primarily due to organic growth and the consolidation of JET-branded stations in the second half of 2009. The cold weather and high electricity prices in the first and fourth quarter of 2010 resulted in higher demand for stationary energy, such as heating oil, compared with the same period in 2009.

Purchase [net of inventory variation] increased from NOK 54.8 billion in 2010 to NOK 63.6 billion in 2011, explained by the same factors described under total revenues and other income. Purchase, net of inventory variation increased from NOK 46.9 billion in 2009 to NOK 54.8 billion in 2010, explained by the same factors described under total revenues and other income.

Operating expenses and selling, general and administrative expenses were down 5% to NOK 7.1 billion in 2011, mainly due to stringent cost control and effects from the cost savings programme. The cost savings programme targets cost elements across Fuel & Retail's value chain, aiming at reducing purchases as well as operating expenses. This was partly offset by increased stand-alone and separation costs of NOK 0.1 billion, due to SFR being a separate publicly listed company.

Operating expenses and selling, general and administrative expenses decreased by 8% in 2010 compared with 2009. The decrease was mainly driven by divestments of non-core business activities, improved portfolio management, reduced credit losses in Central and Eastern Europe and the closure of stations with low throughput and profitability in Scandinavia during 2010. This decrease was partly offset by increased administrative expenses due to increased corporate headquarter costs as Fuel & Retail was separated from Statoil ASA and listed on the Oslo stock exchange in October 2010.

Depreciation, amortisation and net impairment losses decreased from NOK 1.3 billion in 2010 to NOK 1.2 for the full year 2011, primarily due to an impairment in 2010 of NOK 0.1 billion. Depreciation, amortisation and net impairment losses totalled NOK 1.3 billion in 2010, compared with NOK 1.2 billion in 2009. The increase was mainly due to impairment of NOK 0.1 billion in 2010, which was largely related to the Fuel & Retail network in Lithuania.

Depreciation, amortisation and net impairment losses (in NOK billion)	Year ended 31 December				
	2011	2010	2009	11-10 change	10-09 change
Ordinary depreciation	1.1	1.1	1.2	5 %	(7%)
Amortisation of intangible assets	0.0	0.1	0.0	(72 %)	>100 %
Impairments	0.0	0.1	0.0	(100 %)	0 %
Depreciation, amortisation and net impairment losses	1.2	1.3	1.2	(11 %)	8 %

In 2011 **net operating income** decreased by NOK 0.5 billion, to 1.9 billion compared with 2010. The decrease was primarily explained by the gain of NOK 0.3 billion from the sale of Swedegas in the first quarter of 2010. .

In 2010, net operating income was NOK 2.4 billion, compared with NOK 1.3 billion in 2009. Net operating income in 2010 was positively impacted by increased volumes and the effect of improved micro market pricing and implementation of the company owned company operated (COCO) fuel concept. Moreover, the consolidation of JET-branded stations in the second half of 2009 and continued implementation of cost reductions and efficiency initiatives, including divestments of non-core business activities, contributed to increased net operating income in 2010 compared with 2009. A gain of NOK 0.3 billion from the sale of Swedegas was also included in other income in 2010.

4.1.9 Other operations

The Other reporting segment includes activities within Global Strategy and Business Development; Technology, Projects and Drilling; and Corporate Staffs and Services.

In 2011, the Other reporting segment recorded a net operating loss of NOK 0.3 billion, compared to a net operating income of NOK 0.6 billion in 2010, and a net operating loss of NOK 0.7 billion in 2009. 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. The increase in net operating income from 2009 to 2010 was driven by the gain on sale of Tampnet.

4.1.10 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 can 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 the 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 NCS are deemed to be equal to lifted volumes of natural gas from the Norwegian continental shelf (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 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. 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 *Operational review - Proved oil and gas reserves* and *note 33 - Supplementary oil and gas information* in the Consolidated financial statements in this report, 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 2011, mainly as a result of increased cash flows from operating activities and continued portfolio optimisation.

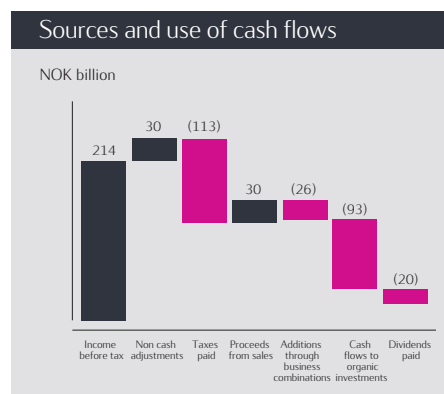
Condensed cash flow statement (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		Change 10-09
			2009 (restated)	Change 11-10	
Income before tax	213.8	136.8	114.9	77.0	21.9
Adjustments to reconcile net income to net cash flows provided by operating activities:					
Depreciation, amortization, impairment	51.4	50.7	53.8	0.7	(3.1)
Exploration expenditures written off	1.5	2.9	7.0	(1.4)	(4.1)
(Gains) losses on foreign currency transactions and balances	4.7	1.5	6.5	3.2	(5.0)
(Gains) losses on sales of assets other items	(27.6)	(1.1)	(0.3)	(26.5)	(0.8)
Cash flows from (to) changes in working capital	1.9	(10.6)	4.6	12.5	(15.2)
Changes in current financial investments	(8.2)	(4.5)	2.7	(3.7)	(7.2)
Changes in net derivative financial instruments	(12.8)	(0.6)	(9.4)	(12.2)	8.8
Taxes paid	(112.6)	(92.3)	(100.5)	(20.3)	8.2
Other changes	(0.7)	(2.2)	(6.4)	1.5	4.3
Cash flows provided by operations	111.5	80.8	73.1	30.7	7.7
Additions to PP&E and intangible assets	(85.1)	(68.1)	(68.0)	(17.0)	(0.0)
Additions through business combinations	(25.7)	0.0	0.0	(25.7)	0.0
Proceeds from sales	29.8	1.9	1.4	27.9	0.5
Other changes	(7.7)	(10.3)	(8.5)	2.6	(1.8)
Cash flows used in investing activities	(88.7)	(76.5)	(75.1)	(12.2)	(1.4)
New non current bonds	10.1	15.6	46.3	(5.5)	(30.8)
Net change in long-term borrowing	(7.4)	(3.3)	(4.9)	(4.1)	1.6
Net change in short-term borrowing	5.2	0.8	(7.1)	4.4	7.9
Dividends paid	(19.9)	(19.1)	(23.1)	(0.8)	4.0
Other changes	(0.7)	5.2	0.1	(5.9)	5.1
Cash flows (used in) provided by financing activities	(12.8)	(0.9)	11.3	(11.8)	(12.2)
Net increase (decrease) in cash flows	10.0	3.4	9.2	6.7	(5.9)

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 111.5 billion in 2011, an increase of NOK 30.7 billion compared to NOK 80.8 billion in 2010. In 2011, the increase was largely driven by increased profitability mainly caused by

higher liquids and gas prices in 2011 compared to 2010, and changes in working capital, partially offset by higher taxes paid of NOK 20.3 billion between the two years. In 2011, cash flows from working capital were NOK 1.9 billion compared with cash flows used of NOK 10.6 billion, a positive variance of NOK 12.5 billion.

Cash flows provided by operations amounted to NOK 80.8 billion in 2010, compared with NOK 73.1 billion in 2009. The increase of NOK 7.7 billion was primarily due to higher cash flows from income before tax and NOK 8.2 billion lower tax payments. These changes were partly offset by a negative change in working capital of NOK 15.2 billion between 2010 and 2009. The use of cash from working capital in 2010 of NOK 10.6 billion was mainly due to an increase in trade and other receivables as a result of higher prices for gas and liquids. In addition, increase in current financial investments of NOK 7.2 billion reflected use of excess cash in 2010 for financial investments.



Cash flows used in investing activities

Cash flows used in investing activities was NOK 88.7 billion in 2011 compared to NOK 76.5 billion in 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 property, plant and equipment of NOK 17.0 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.

Approximately 45% of the investments in 2011 were investments in assets expected to contribute to growth in oil and gas production, including capitalized exploration, while approximately 20% relate to investments in currently producing fields. The remaining 5% represent investments in Statoil's other activities and 30% are related to the acquisition of Brigham Exploration Company.

In 2010, cash flows used in investing activities amounted to NOK 76.5 billion, an increase of NOK 1.4 billion from 2009.

Approximately 54% of the investments in 2010 were investments in assets expected to contribute to growth in oil and gas production, while approximately 32% relate to investments in currently producing fields. The remaining 14% represent investments in Statoil's other activities.

Gross investments

Gross investments are defined as additions to property, plant and equipment (including capitalised financial lease and excluding asset retirement obligation), capitalised exploration expenditure, intangible assets, long-term share investments and non-current loans granted. In 2011, gross investments were NOK 133.6 billion compared to NOK 84.4 billion in 2010, reflecting the acquisition of Brigham Exploration Company of NOK 25.7 billion and the increased activity level in 2011 compared to 2010.

Gross investments amounted to NOK 84.4 billion in 2010, approximately at the same level as in 2009, when gross investments amounted to NOK 86.2 billion.

Gross investments (in NOK billion)	2011	2010 (restated)	For the year ended 31 December		
			2009 (restated)	11-10 Change	10-09 Change
- Development & Production Norway	41.4	31.9	34.9	30 %	(9%)
- Development & Production International	84.4	40.4	39.4	>100 %	3 %
- Marketing, Processing & Renewable Energy	4.6	6.3	7.6	(27 %)	(17%)
- Fuel & Retail	1.5	0.8	2.5	85 %	(67%)
- Other	1.6	4.9	1.8	(67 %)	>100 %
Gross investments	133.6	84.4	86.2	58 %	(2%)

Cash flows used in investing activities are reconciled with gross investments in the table below. For 2011, other changes include additions to property plant and equipment and intangible assets related to Brigham Exploration Company. In 2011 and 2010, the difference between cash flows to investments and gross investments is largely related to proceeds from sales of assets. In 2009, the difference between cash flows to investments and gross investments is largely related to financial lease.

Reconciliation of cash flow to investments (in NOK billion)	2011	For the year ended 31 December 2010 (restated)	2009 (restated)
- Cash flows to investments	88.7	76.5	75.1
- Proceeds from sale of assets	29.8	1.9	1.4
- Financial lease	0.3	1.5	7.5
- Other changes	14.8	4.5	2.1
Gross investments	133.6	84.4	86.2

Cash flows used in/provided by financing activities

Net cash flows used in financing activities in 2011 amounted to NOK 12.8 billion, compared with NOK 0.9 billion in 2010. The NOK 11.8 billion change was mainly related to a net decrease in non-current bonds, net of repayments, 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 with 2010. In addition the change in the net cash flow from non-controlling interests decreased NOK 5.8 billion, mainly related to cash received from Statoil Fuel & Retail ASA shareholders for 46% of Statoil Fuel & Retail's shares in 2010. This change was partially offset by an increase in dividends paid of NOK 0.8 billion, an increase of NOK 4.4 billion in net current bonds, and a decrease of changes in other items of NOK 5.9 billions (other includes collateral liabilities that are used as the security for trading activities).

New non-current bonds in 2011 amounted to NOK 10.1 billion, compared with NOK 15.6 billion in 2010. NOK 7.4 billion of non-current bonds was repaid in 2011, compared with NOK 3.2 billion in 2010.

Net cash flows used in financing activities in 2011 include a dividend of NOK 19.9 billion paid by Statoil ASA to shareholders relating to the annual accounts for 2010, while the dividend paid by Statoil ASA to its shareholders in 2010 relating to the annual accounts for 2009 amounted to NOK 19.1 billion.

Net cash flows used in financing activities in 2010 amounted to NOK 0.9 billion, compared with cash flows provided of NOK 11.3 billion in 2009. The NOK 12.2 billion change was mainly related to a net change in non-current bonds of NOK 29.2 billion due to fewer new bonds being issued in 2010 compared with 2009. The change was partly offset by a change in the net cash flow from non-controlling interests of NOK 5.1 billion. This was mainly related to cash received from Statoil Fuel & Retail ASA shareholders for 46% of Statoil Fuel & Retail's shares, a change of NOK 4.0 billion in dividends paid and a change of NOK 7.9 billion in net current bonds, bank overdrafts and other (other includes collateral liabilities that are used as the security for trading activities).

New non-current bonds in 2010 amounted to NOK 15.6 billion, compared with NOK 46.3 billion in 2009. Of the total new non-current bonds in 2010, NOK 4.0 billion is related to the funding of Statoil Fuel & Retail ASA. The proceeds from the SFR drawdown were applied to repay intercompany debt to Statoil ASA. NOK 3.2 billion of non-current bonds was repaid in 2010, compared with NOK 4.9 billion in 2009.

Net cash flows used in financing activities in 2010 include a dividend of NOK 19.1 billion paid by Statoil ASA to shareholders relating to the annual accounts for 2009, while the dividend paid by Statoil ASA to its shareholders in 2009 relating to the annual accounts for 2008 amounted to NOK 23.1 billion.

4.2.2 Selected balance sheet information

The following tables contain selected financial information relating to our balance sheet and financial ratios that form part of the basis for the subsequent analysis of financial assets and liabilities.

Selected financial data - Balance sheet (in NOK million)	2011	As of 31 December 2010 (restated)	2009 (restated)
ASSETS			
<i>Non-current assets</i>			
Property, plant and equipment	407,585	351,578	342,520
Intangible assets	92,674	43,171	54,344
Investments in associated companies	9,217	8,997	9,424
Deferred tax assets	5,704	1,878	1,960
Pension assets	3,888	5,265	2,694
Derivative financial instruments	32,723	20,563	17,644
Financial investments	15,385	15,357	13,267
Prepayments and financial receivables	3,343	3,945	4,207
Total non-current assets	570,519	450,754	446,060
<i>Current assets</i>			
Inventories	27,770	23,627	20,196
Trade and other receivables	103,261	74,810	58,992
Current tax receivables	573	1,076	179
Derivative financial instruments	6,010	6,074	5,369
Financial investments	19,878	11,509	7,022
Cash and cash equivalents	40,596	30,521	25,286
Total current assets	198,088	147,617	117,044
Assets clasified as held for sale	0	44,890	0
TOTAL ASSETS	768,607	643,261	563,104

Selected financial data - Balance sheet (in NOK million)	2011	As of 31 December 2010 (restated)	2009 (restated)
EQUITY AND LIABILITIES			
<i>Equity</i>			
Share capital	7,972	7,972	7,972
Treasury shares	(20)	(18)	(15)
Additional paid-in capital	41,825	41,789	41,732
Additional paid-in capital related to treasury shares	(1,040)	(952)	(847)
Retained earnings	218,518	164,935	145,909
Other reserves	11,661	5,816	3,568
Statoil shareholders' equity	278,916	219,542	198,319
Non-controlling interests	6,239	6,853	1,799
Total equity	285,155	226,395	200,118
<i>Non-current liabilities</i>			
Bonds, bank loans and finance lease liabilities	111,611	99,797	95,962
Deferred tax liabilities	82,520	78,065	76,335
Pension liabilities	26,984	22,112	21,144
Asset retirement obligations, other provisions and other liabilities	87,304	67,978	55,834
Derivative financial instruments	3,904	3,386	1,657
Total non-current liabilities	312,323	271,338	250,932
<i>Current liabilities</i>			
Trade and other payables	93,967	73,720	60,050
Current tax payable	54,296	46,694	40,994
Bonds, bank loans, commercial papers and collateral liabilities	19,847	11,730	8,150
Derivative financial instruments	3,019	4,161	2,860
Total current liabilities	171,129	136,305	112,054
Liabilities directly associated with the assets classified as held for sale	0	9,223	0
Total liabilities	483,452	416,866	362,986
TOTAL EQUITY AND LIABILITIES	768,607	643,261	563,104

Other financial information	2011	Year ended 31 December	
		2010 (restated)	2009 (restated)
Net debt to capital employed ratio before adjustments (1)	19.9%	23.5%	26.4%
Net debt to capital employed ratio adjusted (2)	21.1%	25.5%	27.6%
Calculated ROACE based on Average Capital Employed before Adjustments (3)	22.1 %	12.6 %	10.6 %
Ratio of earnings to fixed charges (4)	35.2	18.2	7.2

⁽¹⁾ 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.

⁽²⁾ As adjusted. 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 analysis and review - Non-GAAP measures for a reconciliation of capital employed and a description of why we make use of this measure.

⁽³⁾ 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.

⁽⁴⁾ Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortization of capitalized interest and (iv) fixed charges (which have been adjusted for capitalized interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalized interest) and estimated interest within operating leases.

4.2.3 Financial assets and liabilities

Gross interest-bearing financial liabilities were NOK 131.5 billion at the end of 2011, while net interest-bearing financial liabilities before adjustments were NOK 71.0 billion. The net debt to capital employed ratio before adjustments was 19.9%.

Current items

Current items (total current assets minus total current liabilities) increased by NOK 15.7 billion from positive NOK 11.3 billion at 31 December 2010 to positive NOK 27.0 billion at 31 December 2011.

The increase of NOK 15.7 billion was due to increases in current assets such as inventories of NOK 4.1 billion, trade and other receivables of NOK 28.5 billion, current financial investments of NOK 8.4 billion, cash and cash equivalents of NOK 10.1 billion and decrease in other current receivables of NOK 0.1 billion. This was partly offset by increases in current liabilities such as bonds, bank loans, commercial papers and collateral liabilities of NOK 8.1 billion, current tax payable of NOK 7.6 billion, trade and other payables of NOK 20.2 billion and a decrease in other current liabilities of NOK 1.1 billion.

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. Our main sources of liquidity are described below.

Liquidity

Our annual cash flow from operations is highly dependent on oil and gas prices and our levels of production. Economic instability, such as the Euro crisis, may impact our business and cash flows, see Risk factors - The sovereign debt situation in Europe may affect our business. However, our cash flows from operations is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside our control, will cause changes in our cash flows. We will use available liquidity to finance Norwegian petroleum tax payments (due on 1 February, 1 April, 1 June, 1 August, 1 October and 1 December each year), any dividend payment and investments. Our investment programme is spread over the year. There may be a gap between funds from operations and funds required to fund investments, which may be financed by short and long-term borrowings. We aim to keep ratios relating to net debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category. In this context, Statoil carries out various risk assessments, some of them in line with financial matrices used by S&P and Moody's, such as funds from operations over net debt and net debt to capital employed.

Management of the portfolio of security investments, mainly related to equity securities, is held by our insurance captive, Statoil Forsikring AS, and commercial papers and money market investments held by Statoil ASA.

As of 31 December 2011, cash and cash equivalents and current financial investments amounted in total to NOK 60.5 billion, including NOK 40.6 billion in cash and cash equivalents and NOK 19.9 billion in current financial investments (domestic and international capital market investments). Cash and cash equivalents include NOK 4.3 billion deposited with Statoil's US dollar-denominated bank account in Nigeria. There are certain restrictions on the use of cash from Statoil's Nigerian operations following an injunction against Statoil by the Nigerian courts relating to an on-going litigation claim. Both the injunction and the disputed claim have been appealed. Of the total restricted cash at 31 December 2011, NOK 3.9 billion is no longer to be reported as restricted cash from March 2012. Approximately 42% of our liquid assets were held in NOK-denominated assets, 25% in USD, 10% in CHF, 9% in EUR and 14% in other currencies (GBP, DKK), before the effect of currency swaps and forward contracts.

As of 31 December 2010, cash and cash equivalents and current financial investments amounted in total to NOK 42.0 billion, including NOK 30.5 billion in cash and cash equivalents and NOK 11.5 billion in current financial investments (domestic and international capital market investments). Cash and cash equivalents include NOK 2.6 billion deposited with Statoil's US dollar-denominated bank account in Nigeria. Approximately 44% of our liquid assets were held in EUR-denominated assets, 21% in USD, 16% in NOK and 19% in other currencies (GBP, DKK, CAD, BRL), before the effect of currency swaps and forward contracts.

Our general policy is to maintain a liquidity reserve in the form of cash and cash equivalents in our balance sheet, and 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 USD 3 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 2016. Through one more extension option the facility may be further extended to 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.

To secure financial flexibility, 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). Correspondingly, Statoil ASA issued new debt securities in 2010 in the amount of USD 1.25 billion maturing in August 2017 and USD 0.75 billion maturing in August 2040 (an aggregate amount of NOK 11.5 billion). All of the bonds are guaranteed by Statoil Petroleum AS.

On 1 November 2010, Statoil Fuel & Retail ASA drew down NOK 4.0 billion on its term loan facility, maturing in 2013. The facility is part of a multicurrency term and revolving loan facility in the aggregate amount of NOK 7.0 billion that has been entered into with nine international banks. In addition to the NOK 4.0 billion three-year term loan already drawn, the total facility agreement includes a NOK 3.0 billion five-year revolving loan facility.

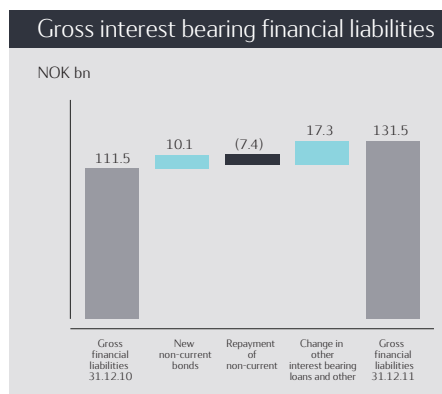
In 2012, Statoil aims to continue to secure financial flexibility and, depending, among other things, on oil and gas price developments, it may issue bonds should market conditions be viewed as attractive. See the section *Risk review - Risk management - Managing financial risk* for more information about liquidity.

Gross interest-bearing financial liabilities

Gross interest-bearing financial liabilities (non-current and current bonds, bank loans and finance liabilities) were NOK 131.5 billion at 31 December 2011, compared with NOK 111.5 billion at 31 December 2010. The NOK 20.0 billion increase was due to increase in current bonds, bank loans, commercial papers and collateral liabilities of NOK 8.2 billion and non-current bonds, bank loans and finance lease liabilities of NOK 11.8 billion.

At 31 December 2010, the financial lease of NOK 8.6 billion related to the Peregrino FPSO vessel, was reclassified from non-current bonds, bank loans and finance lease liabilities to held for sale. In the second quarter of 2011 the financial lease of NOK 4.9 billion related to Statoil's share of the Peregrino FPSO vessel, was reclassified from held for sale to non-current bonds, bank loans and finance lease liabilities.

Gross interest-bearing financial liabilities were NOK 111.5 billion at 31 December 2010, compared with NOK 104.1 billion at 31 December 2009. The NOK 7.4 billion increase was due to a combination of an increase of NOK 3.8 billion in non-current bonds, bank loans and finance lease liabilities and an increase of NOK 3.6 billion in current bonds, bank loans, commercial papers and collateral liabilities.

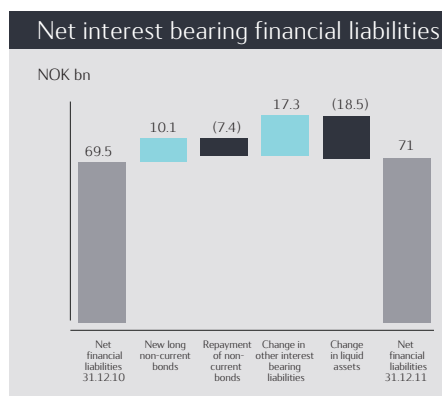


For risk management purposes, currency swaps are used to ensure that Statoil keeps non-current interest-bearing financial liabilities in USD. As a result, most of the group's non-current bonds, bank loans and finance lease liabilities are exposed to changes in the USD/NOK exchange rate.

Net interest-bearing financial liabilities

Net interest-bearing financial liabilities before adjustments were NOK 71.0 billion at 31 December 2011, compared with NOK 69.5 billion at 31 December 2010. The increase of NOK 1.5 billion was mainly related to an increase in gross interest-bearing financial liabilities of NOK 20.0 billion, offset by an increase in cash and cash equivalents and current financial investments of NOK 18.5 billion.

Net interest-bearing financial liabilities adjusted were NOK 76.0 billion at 31 December 2011, compared with NOK 77.4 billion at 31 December 2010. The decrease of NOK 1.4 billion was mainly related to an increase in cash and cash equivalents and current financial investments of NOK 18.5 billion, partly offset by an increase in gross interest-bearing financial liabilities of NOK 20.0 billion and an increased change in non-GAAP adjustments to net interest-bearing financial liabilities before adjustments of NOK 2.7 billion.



The net debt to capital employed ratio

The net debt to capital employed ratio before adjustments, defined as net interest-bearing financial liabilities before adjustments in relation to capital employed before adjustments, was 19.9% in 2011, compared with 23.5% in 2010.

The net debt to capital employed ratio adjusted was 21.1% at 31 December 2011, compared with 25.5% at 31 December 2010. The 4.4 % decrease 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.

In the calculation of net interest-bearing liabilities adjusted, we make certain adjustments, which make net interest-bearing liabilities and the net debt to capital employed adjusted ratio non-GAAP financial measures. For an explanation and calculation of the ratio, see the section *Financial analysis and review - Non-GAAP measures - Net debt to capital employed ratio*.

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 billion and USD 8 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 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 company's central finance function manages the funding, liability and liquidity activities at group level.

Cash, cash equivalents and current financial investments

Cash, cash equivalents and current financial investments amounted to NOK 60.5 billion at 31 December 2011, compared with NOK 42.0 billion at 31 December 2010. The NOK 18.5 billion increase reflects the high cash flow from operations in combination with new non-current bonds in 2011 and proceeds related to the sale of 40% of the Kai Kos Dehseh oil sands project and 40% of the Peregrino offshore heavy oil field which was partially offset by the use of cash for the acquisition of Brigham combined with other high investment activity during 2011.

Cash and cash equivalents were NOK 40.6 billion at 31 December 2011, compared with NOK 30.5 billion at 31 December 2010. Current financial investments, which are part of our cash management, amounted to NOK 19.9 billion at 31 December 2011, compared with NOK 11.5 billion at 31 December 2010.

4.2.4 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2011.

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

Contractual obligations (in NOK billion)	Less than 1 year	1-3 years	As at 31 December, 2011 Payment due by period *		Total
			3-5 years	More than 5 years	
Undiscounted non-current financial liabilities	10.3	28.1	25.6	93.9	157.9
Minimum operating lease payments	21.5	31.5	14.1	16.8	83.9
Nominal minimum payments related to transport capacity, terminal capacity and similar commitments	14.1	24.8	24.7	100.8	164.4
Total contractual obligations	45.9	84.4	64.4	211.5	406.2

* "Less than 1 year" represents 2012; "1-3 years" represents 2013 and 2014, "3-5 years" represents 2015 and 2016, while "More than 5 years" includes amounts for later periods.

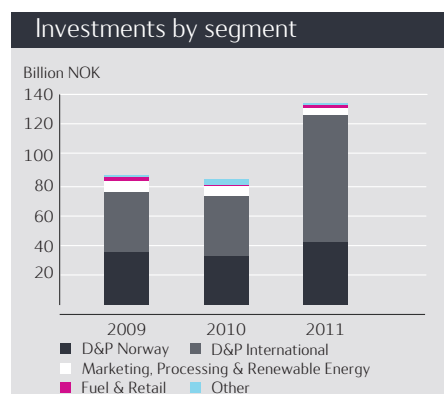
Non-current financial liabilities in the table represent principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to *note 22 - Bonds, bank loans and finance lease liabilities* and *note 27 - Leases*, to our Consolidated Financial Statements included in this report.

Contractual commitments relating to capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 40.1 billion as of 31 December 2011, payment of NOK 25.2 billion of which are due within one year.

The group's projected pension benefit obligation was NOK 75.0 billion, and the fair value of plan assets amounted to NOK 52.0 billion as of 31 December 2011. Actuarial losses amounted to NOK 7,364 million as of 31 December 2011 and are reported as part of the Consolidated statement of comprehensive income. Company contributions are mainly related to employees in Norway.

4.2.5 Investments

Our investments in 2011 were higher than in 2010 mainly due to the acquisition of Brigham Exploration Company.



Capital expenditure

Our capital expenditures from 2009 through 2011 in our five reporting segments are described below, including the allocation per reporting segment as a percentage of gross investments. Capital expenditure is expected to amount to approximately USD 17 billion in 2012, compared to USD 16.3 billion in 2011 (exclusive of acquisitions and capitalisation of financial leases).

	2011	2010 (restated)	For the year ended 31 December 2009 (restated)	11-10 Change	10-09 Change
Gross investments (in NOK billion)					
- Development & Production Norway	41.4	31.9	34.9	30 %	(9%)
- Development & Production International	84.4	40.4	39.4	>100 %	3%
- Marketing, Processing & Renewable Energy	4.6	6.3	7.6	(27 %)	(17%)
- Fuel & Retail	1.5	0.8	2.5	85 %	(67%)
- Other	1.6	4.9	1.8	(67 %)	>100%
Gross investments	133.6	84.4	86.2	58 %	(2%)

	2011	% of total	For the year ended 31 December 2010 (restated)	% of total	2009 (restated)	% of total
Gross investments (in NOK billion)						
- Development & Production Norway	41.4	31%	31.9	38%	34.9	40%
- Development & Production International	84.4	63%	40.4	48%	39.4	46%
- Marketing, Processing & Renewable Energy	4.6	3%	6.3	8%	7.6	9%
- Fuel & Retail	1.5	1%	0.8	1%	2.5	3%
- Other	1.6	1%	4.9	6%	1.8	2%
Gross investments	133.6	100%	84.4	100%	86.2	100%

This section describes our estimated capital expenditure for 2012 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 analysis and review - Liquidity and capital resources - Financial assets and liabilities*.

A substantial proportion of our 2012 capital expenditure will be spent on ongoing and planned development projects in Norway such as Dagny, Goliat, Gudrun, Hyme, Luva, Skarv, Skuld, Valemon, Visund South, the Gullfaks fields and IOR projects.

We currently estimate that a substantial proportion of our 2012 capital expenditure will be spent on the following ongoing and planned development projects internationally: CLOV, PSVM and Pazflor in Angola, In Salah Southern Fields in Algeria, Corrib in Ireland, Jack, St. Malo and BigFoot in the US Gulf of Mexico, Marcellus, Eagle Ford and Bakken onshore USA, and Peregrino in Brazil.

We currently estimate that most of the 2012 capital expenditures spent on midstream and downstream projects will be related to transport solutions for Marcellus Shale Gas, Eagle Ford and on the NCS.

As illustrated in the section *Financial analysis and 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 2011 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 expenditure

We experienced an increase in exploration activities in 2011 compared to the level in 2010. Exploration expenditure in 2011 amounted to NOK 18.8 billion, compared with NOK 16.8 billion in 2010 and NOK 16.9 billion in 2009. Exploration expenditure in 2012 is expected to remain at approximately the same level as in 2011. The group expects to participate in the drilling of approximately 40 wells in 2012. However, no guarantees can be given with regard to the number of wells 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. See the section *Financial analysis and review - Liquidity and capital resources - Critical accounting judgements*.

We use the "successful efforts" method of accounting for oil and natural gas-producing activities. Expenditure on drilling and equipping exploratory wells is capitalised until it is clarified whether there are proved reserves. Expenditure on drilling exploratory wells that do not find proved reserves and geological, geophysical and other exploration expenditure is expensed. Unproved oil and gas properties are assessed quarterly; unsuccessful wells are expensed. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be

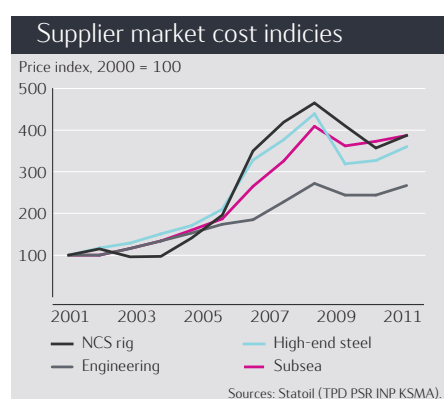
justified, may remain capitalised for more than one year. The main conditions are either that firm plans exist for future drilling in the licence or that a development decision is planned in the near future.

Finally, we may alter the amount, timing or segmental or project allocation of our capital expenditure in anticipation of or as a result of a number of factors outside our control, including, but not limited to:

- exploration and appraisal results, such as favourable or disappointing seismic data or appraisal wells;
- cost escalation, such as higher exploration, production, plant, pipeline or vessel construction costs;
- government approval of projects;
- government awards of new production licences;
- partner approvals;
- the development and availability of satisfactory transport infrastructure;
- the development of markets for our petroleum products and other products, including price trends;
- political, regulatory or tax regime risks;
- accidents such as rig blowouts or fires, and natural hazards;
- adverse weather conditions;
- environmental problems that could lead, for instance, to development restrictions, costs relating to regulatory compliance or the effects of petroleum discharges, political unrest or spills; and
- acts of war, terrorism and sabotage.

4.2.6 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.



Although price pressure has abated since it peaked in 2008, 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 as well as the Group outlook section in the section *Financial analysis and review - Operating and financial review 2011*.

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

4.2.7 Critical accounting judgements

This section describes key sources of estimation uncertainty and the critical judgements that the group has made when applying accounting policies.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRSs as issued by the International Accounting Standards Board (IASB). This means that we are required to make estimates and assumptions. We believe that, of the company's significant accounting policies (see *note 2 - Significant accounting policies*, to our consolidated financial statements included in this report), the following may involve a greater degree of judgement and complexity, which, in turn, could materially affect the net income if various assumptions were significantly changed.

Critical judgements when applying accounting policies

The following are the critical judgements, apart from those involving estimations (see below), that the group 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 in note 2 to the consolidated financial statements, Statoil markets and sells the Norwegian State's share of oil and gas production (SDFI) from the Norwegian continental shelf (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 goods 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 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. This conflict has in 2011 been referred to the IASB by the IFRS Interpretations Committee to be resolved as part of a broader project on equity accounting. Under the requirements of IAS 27, the sale of ownership interests in a wholly-owned entity which would result in the loss of control of a subsidiary requires 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. In making this judgement Statoil considered which guidance best reflects the substance of such transactions, and concluded that the substance is the formation of joint ventures and that the accounting treatment that best reflects the economics of the transactions would be to follow the guidance of IAS 31/SIC 13 which provides the most understandable and relevant representation of these transactions.

Key sources of estimation uncertainty

The preparation of 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, 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 have been estimated by internal experts on the basis of industry standards and governed by criteria established by regulations of the SEC, which requires the use of a price based on a 12-month average for reserve estimation. The Financial Accounting Standards Board (FASB) requirements for supplemental oil and gas disclosures align with the SEC regulations.

Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction 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 such evaluation do not differ materially from management 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. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates used for depreciation and amortisation.

Expected oil and gas reserves are the estimated remaining, commercially recoverable quantities, based on Statoil's judgment 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, which should 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. Expected oil and gas reserves have been estimated by internal experts 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 judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction 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. Future changes in expected oil and gas reserves, for instance as a result of changes in prices, could have a material impact on asset retirement obligations, as well as for the impairment testing of upstream assets, which could have a material effect on operating income as a result of changed impairment charges.

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. Judgments 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, and 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 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 pension benefit 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. Legal and constructive obligations associated with the retirement of non-current assets are recognised at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is capitalised as part of the related non-current asset and allocated to expense over the useful life of the asset.

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. 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. Statoil annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also 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.

4.2.8 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 analysis and review - Liquidity and capital resources - Principal contractual obligations and note 27 - 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 28 - Other commitments and contingencies* in the Consolidated financial statements, for more information.

4.3 Non-GAAP measures

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

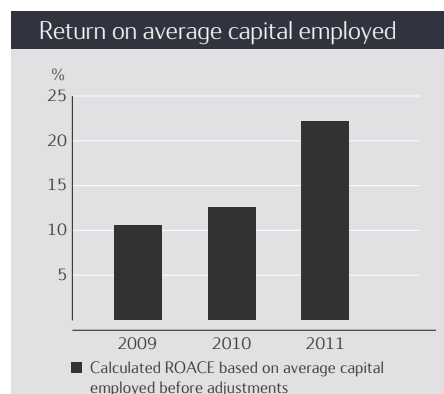
We are subject to SEC regulations regarding the use of "non-GAAP financial measures" in public disclosures. Non-GAAP financial measures are defined as numerical measures that either exclude or include amounts that are not excluded or included in the comparable measures calculated and presented in accordance 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.

4.3.1 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 company's view, this measure provides useful information for both the company 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 22.1% in 2011, compared to 12.6% in 2010 and 10.6% in 2009. The increase from last year was due to doubling of net income adjusted for financial items after tax, slightly offset by a 15% increase in capital employed. The increase from 2009 to 2010 was due to an increase in net income adjusted for financial items after tax, partly offset by a relatively lower increase in capital employed.

Calculation of numerator and denominator used in ROACE calculation (in NOK billion, except percentages)	2011	For the year ended 31 December 2010 (restated)	2009 (restated)	11-10 Change	10-09 Change
Net Income for the year	78.4	37.6	17.7	>100 %	>100 %
Net Financial Items Adjusted for the year	(8.2)	(2.5)	15.6	>100 %	>(100 %)
Calculated Tax on Financial Items for the year 1)	1.6	0.7	(5.0)	>100 %	>(100 %)
Net Income adjusted for Financial Items after Tax (A1)	71.9	35.8	28.3	>100 %	27 %
Capital Employed before Adjustments to Net Interest-bearing Debt: 2)					
Year end 2011	356.1				
Year end 2010	295.9	295.9			
Year end 2009		271.9	271.9		
Year end 2008			263.0		
Sum of Capital Employed for two years (B1)	652.0	567.8	534.9		
Calculated Average Capital Employed: Average Capital Employed before Adjustments to Net Interest-bearing Debt (B1/2)	326.0	283.9	267.4	15 %	6 %
Calculated ROACE: Calculated ROACE based on Average Capital Employed before adjustments (A1/(B1/2))	22.1 %	12.6 %	10.6 %	75 %	19 %

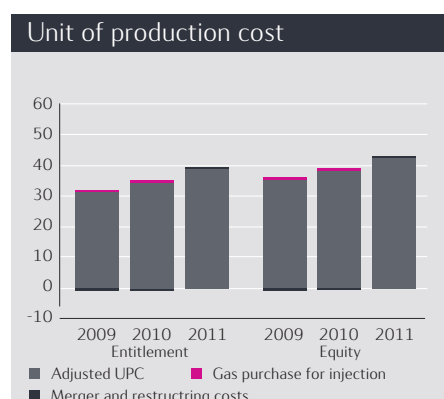
1) Calculated Tax on Financial Items for the year is calculated as the net financial items multiplied by the statutory tax rate in the jurisdiction in which the financial items arose.

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

4.3.2 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.

	2011	For the year ended 31 December 2010 (restated)	2009 (restated)
Reconciliation of overall operating expenses to production cost (in NOK billion)			
Operating expenses, Statoil Group	60.4	57.7	57.0
Deductions of costs not relevant to production cost calculation			
Operating expenses in Business Areas non-upstream	24.5	25.6	26.9
Total operating expenses upstream	35.9	32.0	30.1
¹⁾ Operation over/underlift	(1.2)	0.8	(0.2)
²⁾ Transportation pipeline/vessel upstream	5.2	4.4	5.2
³⁾ Miscellaneous items	3.1	0.5	0.1
Total operating expenses upstream excl. over/underlift & transportation	28.8	26.3	25.0
⁴⁾ Grane gas purchase	0.1	0.8	0.6
⁵⁾ Reversal of restructuring costs	0.0	(0.4)	(0.3)
⁶⁾ Change in ownership interest	0.4	0.1	(0.3)
Total operating expenses upstream for adjusted cost per barrel calculation	28.3	25.9	25.0
Entitlement production used in the cost per barrel calculation (mboe/d)*	1,632	1,687	1,786
Equity production used in the cost per barrel calculation (mboe/d)*	1,832	1,870	1,942

⁽¹⁾ Adjustment related to over-underlift position in the period. Reference is made to chapter 4.1.10 Definitions of reported volumes.

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

⁽³⁾ Adjustment mainly related to royalty payments, removal/abandonment estimates and exclusion of operating cost in associated companies.

⁽⁴⁾ Adjustments related to purchased gas for injection into oil-producing reservoir.

⁽⁵⁾ Adjustment related to partial reversal of restructuring cost arising from the merger and recorded in the fourth quarter 2007.

⁽⁶⁾ Adjustment related to a guarantee in connection with the Veslefrikk field. Reference is made to note 28 Other commitments and contingencies in the Consolidated Financial Statements included in this report.

* Production volumes excluding volumes from associated companies.

	2011	Entitlement production For the year ended 31 December 2010	2009	2011	Equity production For the year ended 31 December 2010	2009
Production cost summary (in NOK per boe)						
Production cost per boe	48.4	42.8	38.4	43.1	38.6	35.3
Adjusted Production cost per boe, excluding reversal of cost related to merger and restructuring cost	48.4	43.5	38.8	43.1	39.2	35.7
Adjusted production cost per boe, excluding reversal of cost related to merger, restructuring and gas injection cost	47.6	42.0	38.4	42.4	37.9	35.3

Entitlement volumes are highly affected by the PSA effects. On average, equity volumes exceeded entitlement volumes by 200 mboe per day in 2011, 182 mboe per day in 2010 and 156 mboe per day in 2009. 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 43.1 per boe in 2011, compared with NOK 38.6 per boe in 2010 and NOK 35.3 per boe in 2009. The adjusted production cost per boe for 2011 was NOK 42.4, compared with NOK 37.9 per boe in 2010 and NOK 35.3 per boe in 2009 based on equity volumes. The adjustments to production cost are reversal of cost related to merger, restructuring and gas injection costs.

4.3.3 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.

	2011	For the year ended 31 December 2010 (Restated)	2009 (Restated)	2008 (Restated)
Calculation of capital employed and net debt to capital employed ratio (in NOK billion, except percentages)				
Statoil shareholders' equity	278.9	219.5	198.3	214.1
Non-controlling interests	6.2	6.9	1.8	2
Total equity (A)	285.2	226.4	200.1	216.1
Bonds, bank loans, commercial papers and collateral liabilities	19.8	11.7	8.2	20.7
Bonds, bank loans and finance lease liabilities	111.6	99.8	96.0	54.6
Gross interest-bearing financial liabilities	131.5	111.5	104.1	75.3
Cash and cash equivalents	40.6	30.5	25.3	18.6
Financial investments	19.9	11.5	7.0	9.7
Cash and cash equivalents and financial investment	60.5	42.0	32.3	28.4
Net interest-bearing financial liabilities before adjustments (B1)	71.0	69.5	71.8	46.9
Other interest-bearing elements ¹⁾	6.9	9.9	6.8	5.9
Marketing instruction adjustment ²⁾	(1.4)	(1.5)	(1.4)	(1.7)
Adjustment for project loan ³⁾	(0.4)	(0.6)	(0.7)	(1.1)
Net interest-bearing liabilities adjusted (B2)	76.0	77.4	76.5	50.0
Calculation of capital employed:				
Capital employed before adjustments to net interest-bearing debt (A+B1)	356.1	295.9	271.9	263.0
Capital employed adjusted (A+B2)	361.2	303.8	276.6	266.1
Calculated net debt to capital employed:				
Net debt to capital employed ratio before adjustments (B1/(A+B1))	19.9%	23.5%	26.4%	17.8 %
Net debt to capital employed ratio adjusted (B2/(A+B2))	21.1%	25.5%	27.6%	18.8 %

1) Adjustments other interest-bearing elements are cash and cash equivalents adjustments regarding collateral deposits classified as cash and cash equivalents in the balance sheet but considered as non-cash in the non-GAAP calculations as well as financial investments in Statoil Forsikring 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 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.

4.4 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.

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, particularly in the Middle East and South America;
- 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 and 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 such as the Norwegian Sea, the Barents Sea, the deepwater US Gulf of Mexico, Azerbaijan, Canada, Egypt, Indonesia, UK, Tanzania, Algeria, Cuba, Faeroes, Angola, Mozambique and Brazil. In some of these countries, 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 cost of drilling, completing and operating wells is often uncertain. As a result, we may experience cost overruns or may be required to curtail, delay or cancel drilling operations because of 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 have entered 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 also 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 failure will 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 gas - could 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 be 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 and 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 could cause 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 and an increase in our costs, and could have a material adverse effect on our operations or financial condition.

Our crisis management systems may be ineffective.

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 seen to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

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

The majority of our proven reserves are on the Norwegian continental shelf (NCS), a maturing resource province. Unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves, our proved reserves will decline as reserves are produced. Successful implementation of our group strategy is critically dependent on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain the long-term replacement of reserves. In addition, the volume of production from oil and natural gas properties generally declines as reserves are depleted. For example, some of our major fields, such as Gullfaks, are dependent on satellite fields to maintain production and, unless efforts to improve the development of satellite fields are successful, production will gradually decline.

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 succeeding 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 of 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 *Operational Review - Competition*.

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 and the Barents Sea, or may be in challenging reservoirs, which 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 to 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 our 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.

The sovereign debt situation in Europe may affect our business.

The European gas market is currently our major market for gas sales. The European sovereign debt crisis has created significant uncertainty and could lead to increased counterparty credit risk. In addition, the eurozone crisis could lead to a prolonged recession in Europe resulting in reduced natural gas demand and lower natural gas prices, which could adversely affect the results of our operations and financial condition.

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 face challenges in the renewable energy sector.

Although energy production from renewables is currently modest in most countries, wind power, solar energy and biofuels are developing into significant industries. We cannot predict the demand for renewables. We believe that technological innovation and the integration of trend-breaking technologies, such as biotechnology and other new ideas, are key to advancing in the renewable energy sector and ensuring a profitable, sustainable, low-carbon energy future. Some of our competitors may be able to invest more in developing technology in the renewable energy sector than we do. Our performance in the renewable energy sector could be impeded if competitors develop or acquire intellectual property rights to technology that we require or if our innovation lags behind the industry. In addition, projects in renewable energy involve emerging technologies, evolving manufacturing techniques and/or cutting-edge implementation. There is little precedent for incorporating certain renewable aspects into new or existing projects.

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 politically, economically and socially unstable areas, which could disrupt our operations.

We have assets located in politically, economically and socially unstable regions around the world where threats such as war, terrorism, border disputes, guerrilla activities, expropriation, nationalisation of property, civil strife, strikes, political unrest and insurrections are present. These threats, or some of them, may impact on our activities in regions such as the Middle East, North Africa, the Caspian and countries such as Nigeria, Angola and Venezuela. The occurrence of incidents resulting from political, economic or social instability could disrupt our operations and further business opportunities in any of these regions and lead to a decline in production. This could have a material adverse effect on the results of our operations and 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 lack well-established 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.

Due to the outbreak of political unrest in Libya in February 2011, the USA, UN, EU and several countries implemented certain sanctions, and Statoil's Libyan operations were suspended. While the sanctions on Libya were largely lifted by the end of 2011 and our production in Libya is resuming, the future impact of the unrest and potential political changes is uncertain.

Our activities in certain countries could lead to US and other 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 6-7-8 of the South Pars gas development project in the Persian Gulf. In total, Statoil's estimated capital expenditures for the offshore development of South Pars phases 6-7-8 is USD 746 million. Final settlement with the partner on the sharing of parts of the capital expenditures may lead to an adjustment of Statoil's final investment amount. Adjusted for an impairment in 2005, a partial reversal of impairment in 2009 and cumulative depreciation charges, the net book value was USD 91 million at year-end 2011. In addition, as a result of the merger with Norsk Hydro's oil and gas business, Statoil owns a 75% interest in the Anaran Block in Iran, which was acquired by Norsk Hydro in 2000. Following the commerciality declaration of the Azar discovery in the Anaran Block in August 2006, Norsk Hydro agreed to conduct negotiations with the National Iranian Oil Company (NIOC) for a master development plan and a development service contract. Statoil had invested USD 104 million in the project, but this amount has been fully written off following an impairment review in 2008. Work on this project was stopped in 2008 and in September 2011 Statoil signed a settlement agreement to close the exploration service contract. Also as a result of the merger with Norsk Hydro's oil and gas business, Statoil now owns a 100% interest in the Khorramabad exploration block, for which Statoil is the operator. In September 2006, Norsk Hydro signed the Khorramabad exploration and development contract with the NIOC, with a total commitment of USD 49.5 million over four years relating to seismic surveys and other exploration activities. We completed the gathering of seismic data in the Khorramabad exploration block in the fourth quarter of 2008. The license expired in November 2010 and Statoil agreed to settle the unexpended minimum commitment. Statoil will not make any future investments in Iran under the present circumstances, but it is committed to fulfilling its contractual obligations. In addition, 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 is operating in full compliance with current US and EU sanctions. See *Operational Review - Development and Production International - International fields - Middle East and North Africa - Iran* for more information.

On 30 September 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. In 2009, Statoil had voluntarily provided officials from the US State Department with information about its activities and investments in Iran.

CISADA came into effect on 1 July 2010. Among other things, CISADA amends certain sections of the Iran Sanctions Act of 1996 (ISA). CISADA requires the President of the United States to sanction companies that make investments that enhance Iran's ability to develop petroleum resources or provide or facilitate the production or importation of refined petroleum products into Iran. Such sanctions could include prohibiting transactions in foreign exchange in which the sanctioned entity has any interest, prohibiting transfers of credit or payments via financial institutions in which the sanctioned entity has any interest, prohibiting property transactions by the sanctioned entity in which the property is subject to the jurisdiction of the United States, the denial of US bank loans, and restrictions on the importation of goods produced by the sanctioned company.

In 2010, the UN and the EU adopted new restrictive measures in relation to Iran. With effect from 14 January 2011, Norway adopted similar regulations. These restrictive measures cover the areas of trade, financial services, energy and transport, as well as additional measures relating to visa bans and asset freezes. In 2011, the US imposed additional sanctions against Iran, including restrictions on transactions with the Central Bank of Iran and lower monetary thresholds for permitted investments in Iran that could contribute to Iran's development of petroleum resources or production of petrochemical products. There is further legislation pending in the US Congress, and additional sanctions may be enacted against Iran. In January 2012, the EU imposed a ban on Iranian origin crude, among other measures, to be phased in over a period of months.

Our activities in Cuba consist of a 30% interest in six deepwater exploration blocks acquired from operator Repsol-YPF in 2006. As of 31 December 2011, we had invested USD 12.5 million in these projects. These activities are not material to our business, financial condition or results of operations, as the total amount invested in these operations represented less than 0.02% of our total assets as of 31 December 2011. While Statoil prequalified to become an operator in Cuba in the first quarter of 2011, this did not lead to increased exposure in 2011.

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 agreeing not to make future investments in, companies that do business with countries designated as state sponsors of terrorism. These policies could have an adverse impact on investment by certain investors in our securities.

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

We have business operations in 41 countries around the world, and any of these countries could modify its tax laws in ways that would adversely affect us. Most of our operations are subject to changes in tax regimes in a similar manner to other companies in our industry. In addition, in the long term, the marginal tax rate in the oil and gas industry tends to change with the price of crude oil. Significant changes in the tax regimes of countries in which we operate could have a material adverse effect on our liquidity and the results of our 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 *Risk review - Risk management - Managing financial risk - Market 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 *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 - including 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.

The crude oil and natural gas reserve data in this annual report are only estimates, and our future production, revenues and expenditures with respect to our reserves may differ materially from these estimates.

The reliability of proved reserve estimates depends on:

- the quality and quantity of our geological, technical and economic data;
- whether the prevailing tax rules and other government regulations, contracts and oil, gas and other prices will remain the same as on the date estimates are made;
- the production performance of our reservoirs; and
- extensive engineering judgments.

Many of the factors, assumptions and variables involved in estimating reserves are beyond our control and may prove to be incorrect over time. The results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserve data. In addition, fluctuations in oil and gas prices will have an impact on our proven reserves relating to fields governed by production sharing agreements (PSAs), since part of our entitlement under PSAs relates to the recovery of development costs. Any downward adjustment could lead to lower future production and thus adversely affect our financial condition, future prospects and market value.

5.1.2 Legal and regulatory risks

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

Compliance with health, safety and environmental laws and regulations that apply to Statoil's operations could materially increase 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.

In particular, following the BP *Deepwater Horizon* oil spill in the US Gulf of Mexico, a number of regulatory changes were instituted in the US, such as the requirement to develop and implement a safety and environmental management system (SEMS programme), the drilling safety rule and the workplace safety rule. In 2011, the US authorities issued guidance to the SEMS programme. Furthermore, on 11 January 2011, the US National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling released its final report that set forth a number of recommendations for changes in environmental laws and regulations for offshore operations in 2010. The US government may choose to implement some of these recommendations, which could result in delays in obtaining drilling permits, approvals of exploration or oil spill response plans. Compliance with any additional regulatory requirements could require

us 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 *Operational Review-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, also may cause us to incur additional costs as regulation of these technologies continues to evolve which 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 of 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, therefore, 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 greenhouse gas emission allowances trading 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 impact 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 license 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 *Operational Review - Applicable laws and regulations*.

5.1.3 Risks related to state ownership

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

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 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 the coordinated ownership strategy for the Norwegian State's shares in Statoil and the SDFI, 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 28 February 2012. A two-thirds majority 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 *Operational review - 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 of 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 expectation - most likely 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, together with risk management methodologies. It regularly receives risk information relevant to the group from our corporate risk department.

We have developed policies aimed at managing the financial volatility inherent in some of our business exposures, and, in accordance with these policies, we enter into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the group level, the business areas responsible for marketing and trading commodities are also responsible for managing commodity-based price risks. The 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.

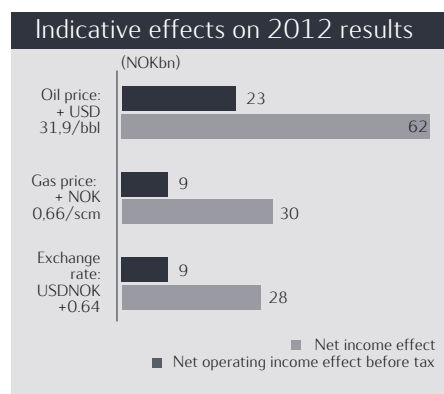
The factors that influence the results of our operation include: the level of crude oil and natural gas prices, trends in the exchange rate between the US dollar (USD) - in which the trading price of crude oil is generally stated and to which natural gas prices are frequently related - and NOK, in which 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 2011, 2010 and 2009.

Yearly average	2011	2010	2009
Crude oil (USD/bbl Brent blend)	111.3	76.5	58.0
Natural gas (NOK per scm)(1)	2.0	1.7	1.9
Refining reference margin (USD/bbl)	2.3	3.9	3.0
USD/NOK average daily exchange rate	5.6	6.1	6.3

(1) Volume-weighted average sales price.



The illustration shows how certain changes in the crude oil price, natural gas contract prices and the USD/NOK exchange rate, if sustained for a full year, could affect our financial results in 2012.

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. The estimated effects on our financial results would differ from those that would actually appear in our consolidated financial statements because our consolidated financial statements would also reflect the effects of depreciation, trading margins, exploration expenses, inflation, potential tax system changes and any hedging programmes in place.

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 debt 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. We manage the risk arising from our interest rate exposure through the use of interest rate derivatives (primarily interest rate swaps) based on a benchmark for the interest reset profile of our non-current financial liabilities portfolio. In general, an increase in the value of USD in relation to NOK can be expected to increase our reported earnings. Please see notes 7, 30 and 31 to the consolidated financial statements for quantitative and qualitative disclosures about market risk.

We sell the Norwegian State's share of oil and natural gas production from the NCS. Amounts payable to the Norwegian State for these purchases are included as "Accounts payable - related parties" in the consolidated balance sheets. The pricing of the crude oil is based on market-reflective prices. NGL prices are based on either attained prices, market value or market-reflective prices.

Statoil sells, in its own name, but for the Norwegian State's account and risk, the State's natural gas production. These sales, as well as related expenses refunded by the State, are shown net in our financial statements. Expenses refunded by the State include expenses incurred in connection with activities and investments that are necessary in order to secure market access and optimise the profit from the sale of the Norwegian State's natural gas. For sales of the Norwegian State's natural gas, both for our own use and to third parties, the payment to the Norwegian State is based on prices attained, a net-back formula

or market value. We purchase a small proportion of the Norwegian State's gas. For further details, see the section *Operational review-Related party transactions*.

High oil prices have contributed to higher earnings and profitability from international projects with production sharing agreements (PSAs) than previously anticipated. Under a PSA, the partners are generally entitled to production volumes that cover the development costs and an agreed share of the remaining volumes. When oil prices are high, this means that these projects will move from a phase where earnings cover development costs to a phase where profits are generated at an earlier point in time. In PSA contracts, the higher the oil price, the sooner the field is profitable and the smaller the share of production that goes to the partners. The actual effect varies between different agreements and countries. These tax regimes are often asymmetric - i.e. the company's upside is somewhat limited, while the company is fully exposed to the downside. See *Financial analysis and review - Sales volumes*, for a description of the impact of the PSA effects.

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 *Operational review-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, Venezuela, USA, Nigeria, Algeria and Angola. 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 group 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 group 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.

Our financial risk management covers market risks, including commodity price risk, interest rate risk, currency risk and equity price risk, liquidity risk, and 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 revenues and the cost of operating, investing and financing. These risks are primarily managed on a short-term basis, with the focus on achieving the highest risk-adjusted returns for the group within the given mandate. Long-term positions (normally longer than one year) or substantial short-term positions are managed at the corporate level, while remaining positions are managed at segment and lower levels in accordance with trading strategies and mandates approved by the CRC.

The group has established guidelines for entering into contractual arrangements (derivatives) in order to manage its commodity price, foreign currency rate and interest rate risk. The group uses both financial and commodity-based derivatives to manage the risks in revenues and the present value of future cash flows.

Commodity price risk

Commodity price risk is our most important market risk. The company is generally not hedged with respect to commodity price risk. However, when marketing volumes we enter into commodity-based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity with the intention to gain additional value to the floating commodity price risk.

Derivatives associated with crude oil and petroleum products are mainly traded on the InterContinental Exchange (ICE) in London, the New York Mercantile Exchange (NYMEX), the OTC Brent market, and in crude and refined products swap markets. Derivatives associated with natural gas and electricity are mainly OTC physical forwards and options, Nordpool forwards and futures traded on the NYMEX and ICE.

The term of oil and refined oil product derivatives is usually less than one year, and the term for natural gas and electricity derivatives is up to three years. The commodity price risk is managed by the crude oil, liquids and products and natural gas organisations in the Marketing, Processing and Renewable Energy

business area. The risks are managed in the trading currencies of the commodities in question, and not necessarily in the functional or reporting currency of the company.

Currency risk

Statoil manages its currency risks for operations on the basis of USD. Fluctuations in exchange rates can have significant effects on our results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates. We only use well-understood, conventional derivative instruments, including futures and options traded on regulated exchanges, OTC swaps, options and forward contracts.

Our cash inflows are largely denominated in or driven by USD, while our cash outflows mainly derive from tax and dividend payments in NOK, as well as certain investments, payments of salaries and various other costs payable in NOK. Accordingly, our exposure to foreign currency rates is primarily related to the USD/NOK exchange rate. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

We further seek to manage short-term currency mismatches by using derivative instruments for both currency and liquidity management purposes. Typically, we purchase NOK during the course of a calendar year in order to cover projected NOK payments of Norwegian income taxes and dividends in the first half of the subsequent year. This means that we from time to time purchase substantial amounts in NOK on a forward basis using derivative instruments.

Interest rate risk

Statoil aims to diversify sources of funding, and to minimise expected funding costs over time. By issuing fixed interest rate debt instead of floating rate debt, Statoil's funding sources become more diversified through reaching a broader spectrum of bond investors compared with issuing floating rate debt. With regard to interest rate risk, Statoil manages the group's interest rate exposure in its non-current financial liabilities by mainly converting the cash flows from fixed coupon payments into floating rate interest payments through the use of interest rate swaps. Statoil currently also has a mandate to keep a proportion of its non-current financial liabilities in fixed interest rates. Bonds are normally issued at fixed rates in a variety of local currencies (including JPY, EUR, CHF, GBP and USD). These bonds are converted into floating USD bonds by using interest rate and currency swaps. For more detailed information about the group's non-current financial liabilities portfolio, see note 22 *Non-current financial liabilities*.

Equity price risk

The group's captive insurance company holds listed equity securities as a part of its portfolio. In addition, the group has some other non-listed equity securities acquired for long-term strategic purposes. By holding these assets, the group is exposed to equity price risk defined as the risk of declining equity prices leading to a decline in the fair value of the group's assets recognised in the balance sheet. The equity price risk in the portfolio held by the group's captive insurance company with the aim of maintaining a moderate risk profile is managed through geographical diversification, the use of broad benchmark indexes and the use of several different fund managers.

Liquidity risk

Liquidity risk is the risk that Statoil will not be able to meet obligations relating to financial liabilities when they become due. The purpose of liquidity and current liability 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 group operational requirements. Statoil focuses on credit and liquidity risk throughout its organisation. In order to ensure financial flexibility, which includes meeting the group's financial obligations, Statoil pursues what it believes to be a conservative liquidity management strategy. To ensure 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 affected by the volatility in oil and gas prices. During 2011 the group'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 level, new long-term funding will be considered.

Short-term funding can be carried out bilaterally through direct borrowing from banks, insurance companies, etc. An alternative is to issue short-term debt securities under one of the existing funding programmes or under documentation established ad hoc. These funding programmes are as follows:

- **A USD 4 billion US commercial paper programme.** This is a flexible programme used for short-term funding.
- **A USD 3 billion committed multi-currency revolving credit facility from international banks, including a USD 1 billion swing-line facility.** The facility was entered into in December 2010. Its availability for draw-downs has been extended by one year until December 2016. The facility agreement contains one more extension option that provides for extension of the facility until December 2017.
- **Uncommitted credit lines.** A short-term funding source occasionally used by Statoil.

In order to have access to sufficient liquidity at all times, Statoil defines and continuously maintains a minimum liquidity reserve, which comprises unused committed external credit facilities, cash and cash equivalents, and current financial investments, excluding the current portion of the investment portfolio held by the group's captive insurance subsidiary.

Liquid assets (in NOK billion)	2011	2010 (restated)	2009 (restated)
Cash & cash equivalents	40.6	30.5	25.3
Financial Investments	19.9	11.5	7.0
Total liquid assets	60.5	42.0	32.3

Funding and liability

As a fundamental principle, we separate investment decisions from financing decisions. 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. This rating ensures necessary predictability when it comes to funding access on favourable 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 debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category 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 free funds from operations over net debt and net debt to capital employed.

Statoil's non-current financial liabilities refinancing risk is controlled by keeping the maximum annual mandatory redemptions as a proportion of capital employed within predefined limits.

Liquidity forecasts serve as tools for financial planning. In order to maintain the necessary financial flexibility, we have requirements for maximum (forecasted) current debt and minimum (forecasted) liquidity reserve. The issuing of non-current financial liabilities is used as a tool for reducing current debt and/or increasing the liquidity reserve. New non-current funding will be initiated if liquidity forecasts uncover non-compliance with given limits, unless further detailed consideration indicates that the non-compliance is likely to be very temporary. In such case, the situation will be further monitored before additional non-current debt is drawn.

For further information about our debenture bonds, bank loans and other debt portfolio profile, see note 22 *Non-current financial liabilities* to the consolidated financial statements.

Statoil's dividend policy includes providing a return to our shareholders through cash dividends and share repurchases. The level of cash dividends and share repurchases can fluctuate in any one year, depending on our assessment of future cash flows, capital expenditure plans, financing requirements and appropriate financial flexibility. See the *Shareholder information* section for additional information about our dividend policy.

Credit risk

Credit risk is the risk that the group's customers or counterparties will cause the group financial loss by failing to honour their obligations. Credit risk arises from credit exposure to customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions.

Key elements of our credit risk management approach include:

- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- Continuously monitoring and managing credit exposure.

Prior to entering into transactions with new counterparties, the group's credit policy requires all counterparties to be formally identified and approved. All sales, trading and financial counterparties are also assigned internal credit ratings as well as exposure limits. Once established, all counterparties are reassessed at least annually and monitored continuously. 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 on the basis of 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.

The group uses risk mitigation tools to reduce or control credit risk, both at 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.

The group has pre-defined limits for the absolute credit risk level allowed at any given time at the group portfolio level as well as maximum credit exposures to individual counterparties. The group monitors the portfolio on a regular basis and individual exposures in relation to limits on a daily basis. Statoil's total credit exposure portfolio is geographically diversified among a number of counterparties in the oil and energy sector, as well as larger oil and gas consumers and financial counterparties. The majority of the group's credit exposure is with investment-grade counterparties. The group actively monitors the eurozone credit exposure due to the current European sovereign debt crisis.

The following table contains the carrying amount of Statoil's financial receivables and derivative financial instruments that are neither past due nor impaired, broken down by the group's assessment of the counterparty's credit risk. Only non-exchange traded instruments are included in current and non-current derivative financial instruments.

As of 31 December 2011, financial counterparties have paid NOK 10.8 billion in cash, which is held by us as collateral to offset part of this credit exposure.

(in NOK million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2011				
Investment grade, rated A or above	1,030	31,148	19,403	3,508
Other investment grade	0	35,806	13,306	2,292
Non-investment grade or not rated	575	27,709	14	132
Total financial asset	1,605	94,663	32,723	5,932
At 31 December 2010				
Investment grade, rated A or above	987	29,614	12,444	4,291
Other investment grade	565	8,132	8,119	1,081
Non-investment grade or not rated	200	30,702	0	640
Total financial asset	1,752	68,448	20,563	6,012
At 31 December 2009				
Investment grade, rated A or above	1,081	25,119	10,975	3,501
Other investment grade	543	5,417	6,669	1,060
Non-investment grade or not rated	0	22,514	0	635
Total financial asset	1,624	53,050	17,644	5,196

Most of our credit risk exposure with counterparties is assessed by us as having an investment grade credit rating. Our assessment of each counterparty's credit risk is often consistent with the credit ratings published by major credit rating agencies, but it may vary on a case-by-case basis due to differences in the timing and/or the judgments inherent in the specific credit risk assessment. Our assessment of each counterparty's credit risk may also change over time due to changes in company-specific or general conditions.

In accordance with our internal credit rating policy, we reassess counterparty credit risk at least annually and assess counterparties that we identify as high risk more frequently. The mandate for setting the credit limit is regularly reviewed with regard to changes in market conditions.

5.2.2 Disclosures about market risk

Statoil uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidity and funding risks. Significant amounts of assets and liabilities are accounted for as financial instruments.

See note 31 to the consolidated financial statements, *Financial instruments by category*, for details of the nature and extent of such positions, and note 31, *Financial instruments: fair value measurement and sensitivity analysis of market risk*, 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 could, individually or in aggregate, have 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	2011	2010	2009	2008	2007
Share price STL (high) (NOK)	160.50	149.20	146.80	214.10	191.50
Share price STL (low) (NOK)	113.70	117.60	108.90	96.40	151.50
Share price STL (average) (NOK)	139.60	131.80	129.50	153.60	169.70
Share price STL year-end (high)	153.50	138.60	144.80	113.90	169.00
Market value-year end (NOK billion)	490	442	462	363	539
Daily turnover (million shares)	8.9	9.7	9.6	13.5	16.5
Earnings per share for income attributable to equity holders of the company diluted	24.70	11.94	5.74	13.58	13.80
P/E 1)	6.2	11.61	25.18	8.39	12.25
Total dividend per share (NOK) 2)	6.50	6.25	6.00	7.25	8.50
Ordinary dividend per share (NOK) 2)	6.50	6.25	6.00	4.40	4.20
Special dividend per share (NOK) 2)	0.00	0.00	0.00	2.85	4.30
Growth in ordinary dividend per share 3)	4.0 %	4.2 %	36.4 %	4.8 %	5.0 %
Growth in total dividend per share	4.0 %	4.2 %	(17.2 %)	(14.7 %)	(6.8 %)
Total dividend per share (USD) 4)	1.08	1.07	1.04	1.26	1.47
Pay-out ratio 5)	26%	52%	104%	53%	61%
Dividend yield 6)	4.2 %	4.5 %	4.1 %	6.4 %	5.0 %
Net debt to capital employed ratio adjusted 7)	21.1 %	25.5 %	27.6 %	17.5 %	
Ordinary shares outstanding , weighted average	3,182,112,843	3,182,574,787	3,183,873,643	3,185,953,538	3,195,866,843
Ordinary shares outstanding, year end	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103	3,188,647,103

⁽¹⁾ Share price at year-end divided by EPS.

⁽²⁾ Proposed cash dividend for 2011.

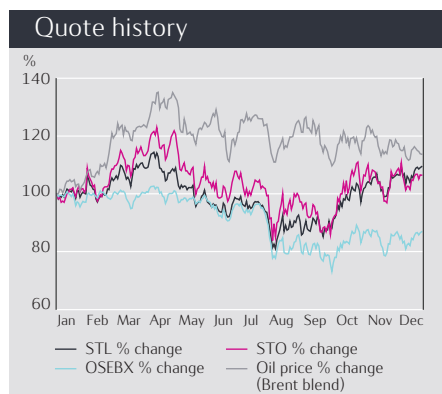
⁽³⁾ Excluding special dividend and share buy-back.

⁽⁴⁾ The USD amounts are based on the Norwegian Central Bank's exchange rate at 31 December 2011.

⁽⁵⁾ Total dividend paid per share divided by EPS.

⁽⁶⁾ Total dividend paid per share divided by year-end share price.

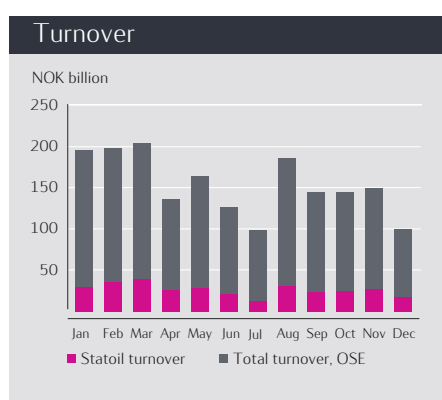
⁽⁷⁾ Net debt to capital employed ratio adjusted for 2010, 2009 and 2008 has been restated. For 2007, the ratio has been omitted because such financial information cannot be provided on a restated basis without unreasonable effort or expense.



As of 31 December 2011, Statoil represented 32.7% of the total value of all companies registered on the Oslo Stock Exchange, with a market value of NOK 489.5 billion.

Statoil's share price closed at NOK 153.50 at the end of 2011.

Taking into consideration the dividend of NOK 6.25 per share paid in 2011, the total return was NOK 21.15 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 6.50 per share for 2011, for approval by the annual general meeting on 15 May 2012. The dividend of NOK 6.50 per share that is proposed to be distributed to our shareholders is equivalent to a direct yield of approximately 4.2%, and we will distribute 26% of our net income from 2011. Net income per share amounted to NOK 24.76, an increase of 107.4% compared with 2010.



The turnover of shares is a measure of traded volumes. On average, 8.9 million Statoil shares were traded on the Oslo Stock Exchange every day in 2011 compared with 9.7 million shares in 2010. Statoil shares accounted for 21% of the total market value traded throughout the year (see illustration), compared with 19% in 2010.

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 2011, Statoil had 100,589 shareholders registered in the Norwegian Central Securities Depository (VPS), down from 102,800 shareholders the year before.

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 is no change in the announced dividend policy that has applied since 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 after 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 2012 on our ordinary shares for the fiscal year 2011.

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

*Proposed

In 2007 and 2008, the total dividend per share consisted of an ordinary dividend and a special dividend. In 2009 and 2010 the dividend per share consisted of an ordinary dividend only. The proposed dividend per share for 2011 is an ordinary dividend only.

The proposed dividend for 2011 will be considered at the annual general meeting on 15 May 2012. The Statoil share will be traded ex-dividend from 16 May 2012, and, if approved, the dividend will be disbursed on 30 May 2012. For US ADR holders, the ex-dividend date will be 17 May 2012.

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 depository converts cash dividends into USD. The dividend will be made available to the depository on 30 May 2012. The depository 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 11 June 2012.

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 2011-2012, 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 2011 and 2010 for subsequent annulment.

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. However, no shares were repurchased in the market for the purpose of subsequent annulment in 2011.

6.2.1 Statoil's share savings plan

Since 2004, Statoil has had a share savings plan for employees of the group. 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 amount 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 at a total nominal value of up to NOK 20,000,000. Shares acquired under this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group'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 2012. This authorisation replaces the previous authorisation to acquire Statoil's own shares for implementation of the share savings plan for employees granted by the annual general meeting on 19 May 2010.

The nominal value of each share is NOK 2.50. With a maximum overall nominal value of NOK 20,000,000, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than eight 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-11	481,000	141.70	3,442,900	4,557,100
Feb-11	493,000	138.64	3,935,900	4,064,100
Mar-11	477,000	143.50	4,412,900	3,587,100
Apr-11	455,000	151.00	4,867,900	3,132,100
May-11	479,000	143.44	5,346,900	2,653,100
Jun-11	517,000	133.32	517,000	7,483,000
Jul-11	514,800	134.22	1,031,800	6,968,200
Aug-11	567,000	122.52	1,598,800	6,401,200
Sep-11	549,000	128.18	2,147,800	5,852,200
Oct-11	519,500	137.44	2,667,300	5,332,700
Nov-11	491,500	148.26	3,158,800	4,841,200
Dec-11	490,500	153.08	3,649,300	4,350,700
Jan-12	529,500	150.85	4,178,800	3,821,200
Feb-12	507,000	157.72	4,685,800	3,314,200
TOTAL	7,070,800 ⁽²⁾	141,35 ⁽³⁾	45,641,900	66,358,100

⁽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 2010. The authorisation was renewed by the annual general meeting on 19 May 2011 maintaining a maximum of eight million shares with a maximum overall nominal value of 20 million for repurchase of shares, and valid until 30 June 2012.

⁽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, 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. The company distributes its share price-sensitive information through the international wire services, Oslo stock exchange in Norway, the Securities and Exchange Commission in the USA, and the company's website.

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). Major services provided by the registrar are investor services for private shareholders, the disbursement of dividend and assistance at our general meetings. DnB NOR bank is currently 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 - <http://www.statoil.com/ir>

Our quarterly presentations and other relevant presentations by management are broadcast directly on the internet, and the related reports are made available together with other relevant information on the company's website.

Ticker Codes:

Oslo Stock Exchange STL

New York Stock Exchange STO

Reuters STL.OL

Bloomberg STL NO

Financial calendar for 2012

08 February	Fourth quarter results 2011 and strategy update
23 March	Publication of annual report 2011
08 May	First quarter 2012
15 May	Annual general meeting
16 May	Share trading ex-dividend
30 May	Dividend payment
26 July	Second quarter 2012
26 October	Third quarter 2012

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 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.

Share price	NOK per ordinary share		USD per ADS	
	High	Low	High	Low
Year ended 31 December				
2007	191.50	151.50	35.19	23.90
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
Quarter ended				
Wednesday, March 31, 2010	149.20	126.90	26.47	21.57
Wednesday, June 30, 2010	147.00	123.90	24.98	19.15
Thursday, September 30, 2010	131.70	117.60	21.59	18.68
Friday, December 31, 2010	140.50	122.40	23.77	19.99
Thursday, March 31, 2011	139.00	113.70	25.78	20.16
Thursday, June 30, 2011	160.50	129.00	29.58	23.44
Friday, September 30, 2011	139.00	113.70	25.78	20.16
Saturday, December 31, 2011	153.50	127.90	26.70	22.03
March up until 12 March 2012	160.70	147.10	28.92	24.88
Month of				
September 2011	129.90	119.50	23.90	20.87
October 2011	145.30	123.50	26.70	20.67
November 2011	150.00	136.30	26.48	23.31
December 2011	153.50	145.20	26.65	24.38
January 2012	159.50	148.10	26.80	24.88
February 2012	160.50	149.10	28.78	25.51
March up until 12 March 2012	160.70	156.10	28.92	27.33

6.4.2 Statoil ADR programme fees

Fees and charges payable by a holder of ADSs.

As depositary, The Bank of New York Mellon 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)	<ul style="list-style-type: none">· 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	<ul style="list-style-type: none">· 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	<ul style="list-style-type: none">· Distribution of securities distributed to holders of deposited securities which are distributed by the Depositary to ADS registered holders
Registration or transfer fees	<ul style="list-style-type: none">· 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	<ul style="list-style-type: none">· Cable, telex and facsimile transmissions (as provided in the deposit agreement)· Converting foreign currency to U.S. 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	<ul style="list-style-type: none">· As necessary
Any charges incurred by the Depositary or its agents for servicing the deposited securities	<ul style="list-style-type: none">· 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 2011, the depositary reimbursed USD 796,343 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 2011:

Category of Expenses	USD Amount Reimbursed for the year ended 31 December 2011
US investor relations expenses and other miscellaneous expenses	796,343
Total Amount Reimbursed	796,343*

* Net of withholding tax paid by the Depositary.

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 2011:

Category of Expenses	USD Amount Waived or Paid for the year ended 31 December 2011
Third-party expenses paid directly by the Depositary*	5,056
Service fees waived by the Depositary	130,000
Total Amount Waived or Paid Directly to Third Parties	135,056

* Statoil paid indirectly USD 13,585 of the third-party expenses paid by the depositary via a decrease in the amount reimbursable to Statoil by the depositary.

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 concerning 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 on 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 amount 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 necessary 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.

The Bank of New York Mellon, 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 The Bank of New York Mellon 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. From 1 January 2012, 3% of the received dividends will be subject to the standard 28 % income tax rate.

Taxation on the realisation of shares

Corporate shareholders resident in Norway for tax purposes are 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, but may be set off against dividends from and capital gains on such shares realised in the same income year. The basis for taxation is 3% of the net capital gain and it is subject to the standard 28% income tax rate. Effective from 2012, corporate shareholders will be exempt from tax on gains.

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 become subject to Norwegian exit taxation on capital gains related to shares in certain circumstances.

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 in taxable years beginning before 1 January 2013 will be eligible to be taxed at a maximum tax rate of 15% so 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 15% maximum tax rate, 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 maximum 15% rate. To the extent 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 special 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 & 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 to this 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.

Year ended December 31	Low	High	Average	End of Period
2007	5.2751	6.4727	5.8610	5.4110
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

	Low	High
2011		
September	5.3737	5.8716
October	5.4184	5.9449
November	5.6027	5.9234
December	5.7301	6.0315

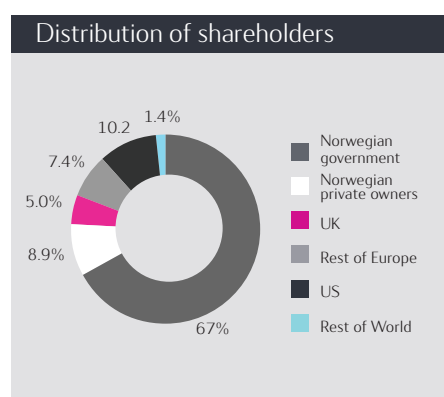
2012		
January	5.8106	6.0545
February	5.5349	5.8408
March (up to and including 12. March 2012)	5.5758	5.7013

On 12 March 2012, the exchange rate announced by the Norges Bank for the Norwegian krone was USD 1.00 = NOK 5.7013.

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

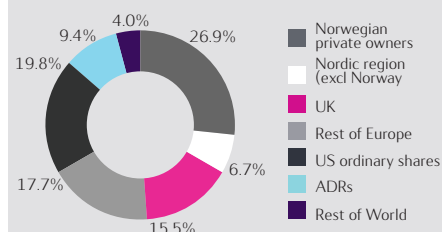
The Norwegian State is the largest shareholder in Statoil, with a direct ownership interest of 67%. Its ownership interest is managed by the Norwegian Ministry of Petroleum and Energy.



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 of two-thirds in Statoil, 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 12 March 2012, the Norwegian State had a 67% direct ownership interest in Statoil and a 3.26 % indirect interest through the National Insurance Fund (Folketrygdfondet), totalling 70.26 %.

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 12 March 2012.

Free float breakdown



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 as depository, pursuant to which American Depositary Receipts (ADRs) representing American Depositary Shares (ADSs) are issued. We have been informed by The Bank of New York Mellon that in the United States, as of March 12, 2012, there were 100,192,295 ADRs outstanding (representing approximately 3.1% of the ordinary shares outstanding). As of March 12, 2012, there were 694 registered holders of ADRs resident in the United States. According to Norwegian Central Securities Depository (VPS) 316,885,160 ordinary shares were held by 535 registered holders resident in the United States representing approximately 10 % of Statoil's ordinary shares in total. The number of beneficial holders is not known. Dividend was paid to approximately 126,980 beneficiaries in the USA in 2011 according to the records of The Bank of New York Mellon. The number of American Depositary Receipts traded on the New York Stock Exchange increased by approximately 24 % during the course of the year to 99.6 million shares at the end of 2011.

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 a 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 12 March 2012		Type	Number of shares	Ownership in %
1	The Norwegian State (Ministry of Petroleum and Energy)		2,136,393,559	67.00
2	Folketrygdfondet (Norwegian national insurance fund)		104,090,569	3.26
3	Bank of New York ADR Department	Nominee	82,224,040	2.58
4	Clearstream Banking	Nominee	61,751,147	1.94
5	State Street Bank	Nominee	35,209,196	1.10
6	The Northern Trust	Nominee	30,512,500	0.96
7	Bank of New York Mellon	Nominee	25,769,709	0.81
8	State Street Bank	Nominee	24,853,198	0.78
9	State Street Bank	Nominee	21,073,588	0.66
10	State Street Bank	Nominee	19,010,117	0.60
11	Bank of New York Mellon Depository Receipts	Nominee	17,968,255	0.56
12	JPMorgan Chase Bank	Nominee	16,920,863	0.53
13	Citibank	Nominee	11,706,545	0.37
14	JPMorgan Chase Bank	Nominee	10,807,041	0.34
15	Bank of New York Mellon	Nominee	10,585,283	0.33
16	Six SIS AG	Nominee	9,951,624	0.31
17	Six SIS AG	Nominee	9,735,542	0.31
18	Danske bank operations	Nominee	9,215,698	0.29
19	The Northern Trust	Nominee	8,936,807	0.28
20	The Northern Trust	Nominee	8,318,431	0.26

Source: Norwegian Central Securities Depository (VPS)

7 Corporate governance

Statoil's objective is to create long-term value for its shareholders through 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 21 October 2010, with limited changes effective from 20 October 2011. The company's compliance with and, if applicable, deviations from, the code's recommendations is commented on, and these comments are made available at www.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 ourselves or through participation in or together with other companies, to engage in exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy, as well as other businesses.

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 the 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.

Following a revision of our articles of association in 2011, shareholders may vote in writing, including through electronic communication, for a period before the general meeting. In order to practice 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 will be described in the notice of the annual general meeting.

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 at 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 www.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 shall 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.

The Statoil 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 whole organisation and to 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. The Ethics Code of Conduct was amended in 2011. The changes were primarily made to clarify certain provisions and to add a provision for the investigation of potential breaches of Statoil's ethical requirements or relevant statutory provisions. This provision was previously part of another internal governing document. The Ethics Code of Conduct is available at www.statoil.com, together with our anti-corruption compliance programme.

In 2011, Statoil launched a new e-learning course on ethics and anti-corruption. The course is mandatory for all employees and other personnel that act on Statoil's behalf and it must be completed by 31 March 2012. Approximately 50% of all our employees have completed the e-learning course as of the end of 2011. In addition to the e-learning course, Statoil runs various ethics and anti-corruption training programmes. Training in ethics and anti-corruption will continue in 2012.

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 the company's supreme body. The objective of the general meeting is to ensure shareholder democracy. Statoil encourages all shareholders to participate in person or by proxy.

The general meeting of shareholders is the company's supreme corporate body. The 2012 annual general meeting (AGM) is scheduled for 15 May 2012 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. Advance voting prior to general meetings will be available from the 2012 AGM.

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:

- 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
- 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
- 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 Depository (VPS), cf. section 4-10 of the Norwegian Public Limited Liability Companies Act, and the beneficial shareholder wants to vote for their shares, the beneficial shareholder must re-register the shares in a separate VPS account in their own name prior to the general meeting. If the holder can prove that such steps have been taken and that the holder has a de facto shareholder interest in the company, the holder may, in the company's opinion, vote for the shares. Decisions regarding voting rights for shareholders and proxy holders are made by the person opening the meeting, whose decisions may be reversed by the general meeting by simple majority vote.

The minutes of the AGM are made available on Statoil's website immediately after the AGM.

As regards 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 to issues of new shares by us. The preferential right to subscribe to 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 USA may require us to file a registration statement in the USA 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. According 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, partner in Considium Consulting Group AS
- Tom Rathke, managing director, Vital Forsikring and executive vice president, DNB
- Ingrid Dramdal Rasmussen, director general, department for economic and administrative affairs, Norwegian Ministry of Petroleum and Energy

The nomination committee held 10 meetings in 2011.

The instructions for the nomination committee, including the rules of procedure, are available at www.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 31.12.2011	Share ownership for members as of 12.03.2012	First time elected	Expiration date of current term
Olaug Svarva	Managing director, Folketrygdfondet	Oslo	1957	Chair, Shareholder elected	No	0	0	2007	2012
Idar Kreutzer	CEO, Storebrand	Oslo	1962	Deputy chair, Shareholder elected	No	0	0	2007	2012
Karin Aslaksen	Executive vice president, Orkla ASA	Hosle	1959	Shareholder elected	No	0	0	2008	2012
Greger Mannsverk	Managing director, Bergen Group Kimek AS	Kirkenes	1961	Shareholder elected	No	0	0	2002	2012
Steinar Olsen	Senior Advisor, External Relations & Government Affairs, Schlumberger	Stavanger	1949	Shareholder elected	No	0	0	2007	2012
Ingvald Strømmen	Dean at Norwegian University of Science and Technology (NTNU)	Ranheim	1950	Shareholder elected	No	0	0	2006	2012
Rune Bjerke	President and CEO, DNB	Oslo	1960	Shareholder elected	No	0	0	2007	2012
Tore Ulstein	Deputy CEO, Ulstein Group	Ulsteinvik	1967	Shareholder elected	No	0	0	2008	2012
Live Haukvik Aker	Partner, Considium Consulting Group AS	Tønsberg	1963	Shareholder elected	No	0	0	2010	2012
Thor Oscar Bolstad	Manager, Herøya Industripark, Norsk Hydro ASA	Porsgrunn	1954	Shareholder elected	No	0	0	2010	2012
Barbro Hætta-Jacobsen	Medical doctor, University Hospital of Nord-Norge	Harstad	1972	Shareholder elected	No	0	0	2010	2012
Siri Kalvig	University of Stavanger, StormGeo AS	Paris	1970	Shareholder	No	0	0	2010	2012
Eldfrid Irene Hognestad	Union representative Tekna, Advisor Benchmarking	Stavanger	1966	Employee representative	No	1065	394	2009	2013
Stig Lægreid	Union representative, NITO	Oslo	1963	Employee representative	No	727	981	2009	2013
Per Martin Labråthen	Union representative, Industri Energi. Production technician	Brevik	1961	Employee representative	No	1413	1596	2007	2013
Anne K.S. Horneland	Union representative, Industri Energi	Hafrsfjord	1956	Employee representative	No	2526	2825	2006	2013
Jan-Eirik Feste	Union representative, YS	Lindås	1952	Employee representative	No	659	837	2008	2013
Oddbjørn Viken	Union representative, Tekna. Production supervisor	Røyken	1961	Employee representative	No	2581	2913	2009	2013
Per Helge Ødegård	Union representative, Lederne. Discipl resp operation process	Porsgrunn	1963	Employee representative, observer	No	1386	1571	1994	2013
Frode Solberg	Union representative, Industri Energi	Bergen	1969	Employee representative, observer	No	0	0	2009	2013
Brit Gunn Ersland	Union representative, Tekna. Principal Engineer	Bergen	1960	Employee representative, observer	No	1518	1744	2011	2013

An election of the employee representatives in the corporate assembly was held in early 2011. With effect from 26 April 2011, Oddbjørn Viken (former observer) was elected as member and Per Helge Ødegård (former member) and Brit Gunn Ersland were elected as observers. Anne Synnøve Hebnes 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 2011.

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 must consist of between nine and 11 members. The management is not represented on the board, and all shareholder representatives on the board are independent.

At present, Statoil's board of directors consists of 10 members. As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board member service contracts that provide for benefits upon termination of office. Statoil's board of directors has determined that, in its judgement, all of the shareholder representatives on the board are independent as defined by the Norwegian Code of Practice for Corporate Governance.

The board of directors of Statoil ASA is responsible for the overall management of the Statoil group, and for supervising the group's activities in general. The board of directors handles matters of major importance or of an extraordinary nature. However, it may require the management to refer any matter to it. The board of directors appoints the president and chief executive officer (CEO), and stipulates the job instructions, powers of attorney and terms and conditions of employment for the president and CEO.

The board of directors has three sub-committees - the audit committee, the HSE and ethics committee, and the compensation committee.

The board held 15 meetings in 2011. Average attendance at board meetings was 93.3%.

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 2012.

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 2011: 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, latterly 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 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 2011, Svein Rennemo participated in 14 board meetings and four meetings of the compensation committee. Rennemo is a Norwegian citizen and resident.



Marit Arnstad

Marit Arnstad

Position: Deputy chair of the board and member of the board's HSE and ethics committee.

Born: 1962

Term of office: Member of the board of Statoil ASA since June 2006, deputy chair since 1 October 2007. Up for election in 2012.

Independent: Yes

Other directorships: Chair of the board of the Norwegian University of Science and Technology (NTNU) and of Statskog SF. Deputy chair of the board of Polaris Media ASA. Board member of Aker Seafoods ASA and Maja Teknobygg AS.

Number of shares in Statoil ASA as of 31 December 2011: None

Loans from Statoil: None

Experience: Arnstad is a lawyer with the law firm Arntzen de Besche Trondheim AS. Arnstad was the Norwegian Minister of Petroleum and Energy during the period 1997-2000. She was a member of the Norwegian parliament (the Storting),

representing the Centre Party from 1993 to 1997 and 2001 to 2005, and was leader of the party's parliamentary group from 2003 to 2005. Before 1993, she was a higher executive officer with the Norwegian Ministry of the Environment.

Education: Law graduate (cand. jur.) 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 2011, Marit Arnstad participated in 14 board meetings and two meetings of the HSE and ethics committee. Arnstad is a Norwegian citizen and resident.



Roy Franklin

Roy Franklin

Position: Member of the board, the board's audit committee and chair of the HSE and ethics committee.

Born: 1953

Term of office: Member of the board of Statoil ASA since 1 October 2007. Up for election in 2012.

Independent: Yes

Other directorships: Non-executive chair of the board of Keller Group plc, a London-based ground 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 2011: 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 2011, Roy Franklin participated in 13 board meetings, three meetings of the audit committee and four meetings of the 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 HSE and ethics committee.

Born: 1945

Term of office: Member of the board of Statoil ASA from 1 September 2010. Up for election in 2012.

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 2011: 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.

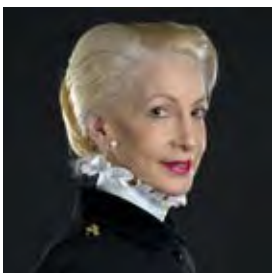
From 2007-2010, he was special adviser for international energy and climate issues at the Norwegian Ministry of Foreign Affairs.

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 2011, Bjørn Tore Godal participated in 15 board meetings, seven meetings of the compensation committee and four meetings of the 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 2012.

Independent: Yes

Other directorships: Board member and chair of the UK Pension Protection Fund and Motricity Inc, 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 2011: 2,488

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 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 2011, Lady Barbara Judge participated in 13 board meetings and six meetings of the audit committee. Lady Judge holds American and British citizenships and lives in London.



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 2012.

Independent: Yes

Other directorships: No

Number of shares in Statoil ASA as of 31 December 2011: 2,600

Loans from Statoil: None

Experience: Chief Strategy & Transformation Officer of Maersk Line, the largest container shipping company in the world and part of A.P. Møller - 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 2011, Jakob Stausholm participated in 15 board meetings, six meetings of the audit committee and one meeting of the HSE and ethics committee. Stausholm is a Danish citizen and lives in Denmark.



Grace Reksten Skaugen

Grace Reksten Skaugen

Position: Member 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 2012.

Independent: Yes

Other directorships: Chair of the boards of Entra Eiendom AS, Ferd Holding and Norsk Institutt for Styremedlemmer, and member of the board of 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 2011: 400

Loans from Statoil: None

Experience: Self-employed business consultant. She was a director in corporate finance in 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 2011, Grace Reksten Skaugen participated in 14 board meetings and seven meetings of the compensation committee. Reksten Skaugen is a Norwegian citizen and resident.



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 2011: 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 2011, Lill-Heidi Bakkerud participated in 13 board meetings and four meetings of the 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 2011: 2,235

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 2011, Morten Svaan participated in 15 board meetings and six meetings of the 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 2011: 3,462

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 2011, Einar Arne Iversen participated in 15 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 committee member.

At year-end 2011, the audit committee members were Jakob Stausholm (chair), Barbara Judge, Roy Franklin 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 provisions of 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, ref. 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 its evaluation of the qualifications and independence of the auditor proposed for election, the audit committee makes a recommendation to the board of directors, the corporate assembly and the general meeting concerning the appointment of the external auditor. 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 group.

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 2011. There was 91.7% attendance at the committee's meetings.

The committee's mandate is available at www.statoil.com/auditcommittee.

7.6.1.1 Audit committee financial expert

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.

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 2011, 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 2011 and attendance was 85.7%.

For a more detailed description of the objective and duties of the compensation committee, please see the Instructions for the compensation committee available at www.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).

In 2010, Statoil's board of directors decided to establish a new 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 Marit Arnstad, Bjørn Tore Godal 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 four meetings in 2011, and attendance was 87.5%.

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 www.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 also appoints the corporate executive committee (CEC). Each of the CEC members 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 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 2011: 41,647

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.



Torgim Reitan. Chief financial officer (CFO)

Torgim 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 2011: 12,094

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: Torgim 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 in Statoil ASA from 1 January 2011.

External offices: None.

Number of shares in Statoil as of 31 December 2011: 5,540

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, holding various managerial positions including 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 2011: 17,129

Loans from Statoil: None

Experience: Joined Statoil in 1980 and has since held several management positions in the group, mainly in the fields of accounting and finance, including the position of CFO from October 2003 until 31 December 2010.

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, Exploration & Production Norway

Øystein Michelsen

Born: 1956

Position: Executive vice president in Statoil ASA since 10 November 2008.

External offices: Member of the board of Oljeindustriens Landsforening (OLF, the Norwegian Oil Industry Association)

Number of shares in Statoil ASA as of 31 December 2011: 14,205

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.



Peter Mellbye. Executive vice president Development and Production International

Peter Mellbye

Born: 1949

Position: Executive vice president in Statoil ASA since 1992.

External offices: Member of the board of the Energy Policy Foundation of Norway (EPF).

Number of shares in Statoil ASA as of 31 December 2011: 20,977

Loans from Statoil: None

Experience: Worked for the Norwegian Ministry of Trade and the Norwegian Export Council before joining Statoil in 1982. Held several central management positions in Statoil. Executive vice president of Natural Gas from 1992 to 2004.

Education: Cand. polit. degree from the University of Oslo.

Family relations: No family relations to other members of the CEC, members of the board or the corporate assembly.

Other matters: Peter Mellbye is a Norwegian citizen and resident. Mr. Mellbye has indicated that he will retire on 1 September 2012. He will be succeeded by Lars Christian Bacher.



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.

Number of shares in Statoil ASA as of 31 December 2011: 4,516 shares

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 previously 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 2011: 27,967

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 2011: 11,528

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 2011: 21,309

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.

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 2011, aggregate compensation totalling NOK 928,000 was paid to the members of the corporate assembly, NOK 4,655,000 to the members of the board of directors and NOK 58,407,000 to the members of the corporate executive committee (all in rounded figures).

Detailed information about the individual compensation paid to the members of the board of directors and members of the corporate executive committee in 2011 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	632		38		670
Marit Arnstad	403			15	418
Grace Reksten Skaugen	321		75		396
Roy Franklin	437	115		63	615
Jakob Stausholm	321	178			499
Bjørn Tore Godal	321		53	31	405
Lady Barbara Judge	418	115			533
Lill-Heidi Bakkerud	321			31	352
Morten Svaan	321	115			436
Einar Arne Iversen	321				321
Geir Nilsen*	10				10
Total	3,826	523	166	140	4,655

* Deputy member of the board of directors (employee representative)

Management remuneration in 2011 (in NOK thousand)

Members of corporate executive committee	Fixed remuneration		Annual variable pay	Taxable benefits in kind	Taxable reimbursements	Taxable salary	Non-taxable benefits in kind	Non-taxable reimbursements	Non-taxable salary	Total remuneration	Estimated pension cost 3)	Estimated present value of pension obligation
	Base pay 1)	LTI 2)										
Lund Helge (CEO)	6,970	1,986	2,139	566	18	11,679	489	28	517	12,196	4,733	36,536
Reitan Torgir (CFO)	2,798	588	527	245	43	4,201	62	16	78	4,279	583	10,989
Sjøblom Tove Stühr (Executive vice president Corporate staffs and services)	2,369	563	565	246	10	3,753	327	109	436	4,189	559	12,607
Mellbye Peter (Executive vice president Development & Production International)	3,752	854	849	330	22	5,807	0	30	30	5,837	1,045	41,673
Dodson Timothy (Executive vice president Exploration)	3,055	650	586	148	21	4,460	425	30	455	4,915	897	17,806
Øvrum Margareth (Executive vice president, Technology, Projects & Drilling)	3,386	778	842	166	13	5,185	208	24	232	5,417	961	33,809
Michelsen Øystein (Executive vice president Development & Production Norway)	3,274	785	703	316	5	5,083	232	56	288	5,371	792	26,738
Sætre Eldar (Executive vice president Marketing, Processing and Renewable Energy)	3,252	782	850	351	18	5,253	0	30	30	5,283	921	32,871
Maloney William (Executive vice president Development & Production North America) 4)	3,545	561	561	714	3	5,384	165	0	165	5,549	550	
Knight John (Executive vice president Global Strategy & Business Development) 4)	4,580	0	0	790	0	5,370	0	0	0	5,370	916	
Total	36,981	7,547	7,622	3,872	153	56,175	1,908	323	2,231	58,406	11,957	213,029

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

2) The fixed long-term incentive (LTI) element implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment. The LTI element is presented the year it is granted.

Members of the corporate executive committee employed by non-Norwegian subsidiaries have an LTI scheme deviating from the model used in the parent company. A net amount equivalent to the annual variable pay is used for purchasing Statoil shares.

3) Pension cost is calculated based on actuarial assumptions and pensionable salary at 31 December 2011 and is recognised as pension cost in the Statement of income for 2011. Payroll tax is not included.

Members of the corporate executive committee employed by non-Norwegian subsidiaries have a defined contribution scheme.

4) Members of the corporate executive committee employed by non-Norwegian subsidiaries and not resident in Norway.

Statoil's remuneration policy

Statoil's remuneration policy is closely linked to the company's people policy and core values. 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.

The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and determining salaries and other remuneration for the corporate executive committee, is in accordance with the provisions of the Norwegian Public Limited Liability Companies Act paragraphs 5-6 and 6-16 a and the board's Rules of Procedure as amended on 9 December 2010.

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

Fixed remuneration

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

Base salary

We offer base salary levels that 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) system

Statoil will continue the established long-term incentive system for a limited number of senior executives, including the members of the corporate executive committee.

The long-term incentive system is a fixed, monetary compensation calculated as a proportion of the participant's base salary; ranging from 20% to 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 on both short-term and long-term goals and results. By ensuring that our top executives are holders of company shares, the long-term incentive system 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 2012.

The chief executive officer is entitled to an 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 to 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.

The effect of remuneration policies 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 review 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 are reflective of the level and impact of the position and are not directly linked to the incumbent's performance.

The goals that form 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, 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 and address the behaviour required and expected in order to achieve our delivery goals.

The performance evaluation is an overall evaluation combining measurement and assessment of performance in relation to 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 against 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 used to significantly reduce the likelihood that remuneration policies can 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 on the basis of an overall assessment of the performance in relation to various targets, including, but not limited to, the company's relative TSR.

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.

Individually, each member of the corporate assembly owned less than 1% of outstanding Statoil shares as of 31 December 2011 and as of 12 March 2012. In aggregate, members of the corporate assembly owned a total of 11,875 shares as of 31 December 2011 and a total of 12,861 shares as of 12 March 2012. 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.

Ownership of Statoil shares (including share ownership of «close associates»)	As of 31 December 2011	As of 12 March 2012
Members of the corporate executive committee		
Helge Lund	41,647	44,104
Torgim Reitan	12,094	12,915
Margareth Øvrum	21,309	22,589
Eldar Sætre	17,129	18,072
Tove Stuhr Sjøblom	5,540	5,877
Peter Mellbye	20,977	21,920
Øystein Michelsen	14,205	15,380
Tim Dodson	11,528	12,285
William Maloney	4,516	4,807
John Knight	27,967	27,967
Members of the board of directors		
Svein Rennemo	10,000	10,000
Marit Arnstad	0	0
Grace Reksten Skaugen	400	400
Bjørn Tore Godal	0	0
Lady Barbara Judge	2,488	2,488
Jakob Stausholm	2,600	2,600
Roy Franklin	0	0
Lill-Heidi Bakkerud	330	330
Morten Svaan	2,235	2,526
Einar Arne Iversen	3,462	3,706

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 for 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 proposed types of services 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 2011

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.

Ernst & Young acted as the company's independent auditor. The table below itemises the expensed remuneration paid to the independent auditor in 2011, 2010 and 2009, respectively:

(in NOK million, excluding VAT)	Audit fee	Audit related fee	Other service fee	Total
2011				
Ernst & Young - Norway	36.6	5.0	3.3	44.9
Ernst & Young - outside Norway	25.8	1.8	0.0	27.6
Total	62.4	6.8	3.3	72.5
2010				
Ernst & Young - Norway	35.2	12.2	0.1	47.5
Ernst & Young - outside Norway	29.3	2.0	0.1	31.4
Total	64.5	14.2	0.2	78.9
2009				
Ernst & Young - Norway	34.2	5.3	3.7	43.2
Ernst & Young - outside Norway	27.1	1.5	0.9	29.5
Total	61.3	6.8	4.6	72.7

All fees included in the table were approved by the audit committee.

Audit fee is defined as the standard audit work that must be performed every year in order to issue an opinion on Statoil's consolidated financial statements and to issue reports on the IFRS 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 fee includes 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 fee includes services provided by the auditors within the framework of the Sarbanes-Oxley Act, i.e. certain agreed procedures.

Audit fees amounting to NOK 8.8 million, NOK 8.8 million and NOK 8.9 million relating to Statoil-operated licences were paid to Ernst & Young for the years 2011, 2010 and 2009, respectively.

Proposed change in Registrant's Certifying Accountant

While Ernst & Young has not resigned, declined to stand for re-election or been dismissed, on 10 February 2012, Statoil announced that it will propose for the corporate assembly to forward a motion to the annual general meeting of shareholders with a recommendation to elect KPMG as the independent auditor commencing with accounting year 2012. Assuming acceptance of the proposal and passage of the recommended motion, the engagement of Ernst & Young is expected to terminate upon election of the independent auditor at Statoil's annual general meeting of shareholders held on 15 May 2012. This announcement followed a comprehensive review and evaluation by Statoil of relevant candidates as part of work to periodically assess the independent auditor consistent with corporate governance standards. The proposed change is not related to any disagreements with Ernst & Young on any matter of accounting principles or practices. Ernst & Young has been Statoil's auditor for more than 20 years. Statoil has been very pleased with the services of Ernst & Young through more than two decades.

7.12 Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures

Our 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 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 our 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).

In accordance with guidelines established by the SEC, a company may exclude acquisitions from its assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired business. The management has excluded from its assessment of internal control over financial reporting the internal controls of Brigham Exploration Company, which was acquired by Statoil on 1 December 2011, and whose financial statements reflect total assets and total liabilities of NOK 42 676 million and NOK 13 276 million respectively as of 31 December 2011 and total revenues and other income and net income of NOK 465 million and NOK 35 million respectively for the period from 1 December to 31 December 2011 included in our consolidated financial statements as of and for the year ended 31 December 2011.

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 2011 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 2011 has been audited by Ernst & Young AS, an independent registered public accounting firm that also audits our 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 of 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 million)	Note	2011	For the year ended 31 December 2010 (restated)	2009 (restated)
REVENUES AND OTHER INCOME				
Revenues		645,599	526,950	462,519
Net income from associated companies	15	1,264	1,168	1,457
Other income		23,342	1,797	1,374
Total revenues and other income	4	670,205	529,915	465,350
OPERATING EXPENSES				
Purchases [net of inventory variation]		(319,605)	(257,436)	(205,870)
Operating expenses		(60,419)	(57,670)	(56,974)
Selling, general and administrative expenses		(13,208)	(11,081)	(10,321)
Depreciation, amortisation and net impairment losses	13, 14	(51,350)	(50,694)	(53,830)
Exploration expenses	14	(13,839)	(15,773)	(16,686)
Total operating expenses		(458,421)	(392,654)	(343,681)
Net operating income	4	211,784	137,261	121,669
FINANCIAL ITEMS				
Net foreign exchange gains (losses)		365	(1,826)	1,989
Interest income and other financial items		1,307	3,113	3,708
Interest and other finance expenses		385	(1,722)	(12,456)
Net financial items	10	2,057	(435)	(6,759)
Income before tax		213,841	136,826	114,910
Income tax	11	(135,398)	(99,179)	(97,195)
Net income		78,443	37,647	17,715
Attributable to:				
Equity holders of the company		78,787	38,082	18,313
Non-controlling interests		(344)	(435)	(598)
		78,443	37,647	17,715
Earnings per share for income attributable to equity holders of the company:				
Basic	12	24.76	11.97	5.75
Diluted		24.70	11.94	5.74

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK million)	Note	For the year ended 31 December		
		2011	2010 (restated)	2009 (restated)
Net income		78,443	37,647	17,715
Foreign currency translation differences		6,054	2,039	(13,637)
Actuarial gains (losses) on employee retirement benefit plans	23	(7,364)	(33)	3,191
Change in fair value of available for sale financial assets	16	(209)	209	(66)
Income tax effect on income and expense recognised in OCI		2,028	16	(742)
Other comprehensive income		509	2,231	(11,254)
Total comprehensive income		78,952	39,878	6,461
Attributable to:				
Equity holders of the company		79,296	40,313	7,059
Non-controlling interests		(344)	(435)	(598)
		78,952	39,878	6,461

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2011	At 31 December 2010 (restated)	At 31 December 2009 (restated)
ASSETS				
<i>Non-current assets</i>				
Property, plant and equipment	13	407,585	351,578	342,520
Intangible assets	14	92,674	43,171	54,344
Investments in associated companies	15	9,217	8,997	9,424
Deferred tax assets	11	5,704	1,878	1,960
Pension assets	23	3,888	5,265	2,694
Derivative financial instruments	30	32,723	20,563	17,644
Financial investments	16	15,385	15,357	13,267
Prepayments and financial receivables	16	3,343	3,945	4,207
Total non-current assets		570,519	450,754	446,060
<i>Current assets</i>				
Inventories	17	27,770	23,627	20,196
Trade and other receivables	18	103,261	74,810	58,992
Current tax receivables		573	1,076	179
Derivative financial instruments	30	6,010	6,074	5,369
Financial investments	19	19,878	11,509	7,022
Cash and cash equivalents	20	40,596	30,521	25,286
Total current assets		198,088	147,617	117,044
Assets clasified as held for sale	5	0	44,890	0
TOTAL ASSETS		768,607	643,261	563,104

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2011	At 31 December 2010 (restated)	At 31 December 2009 (restated)
EQUITY AND LIABILITIES				
<i>Equity</i>				
Share capital		7,972	7,972	7,972
Treasury shares		(20)	(18)	(15)
Additional paid-in capital		41,825	41,789	41,732
Additional paid-in capital related to treasury shares		(1,040)	(952)	(847)
Retained earnings		218,518	164,935	145,909
Other reserves		11,661	5,816	3,568
<hr/>				
Statoil shareholders' equity		278,916	219,542	198,319
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Non-controlling interests		6,239	6,853	1,799
<hr/>				
Total equity	21	285,155	226,395	200,118
<hr/>				
<i>Non-current liabilities</i>				
Bonds, bank loans and finance lease liabilities	22	111,611	99,797	95,962
Deferred tax liabilities	11	82,520	78,065	76,335
Pension liabilities	23	26,984	22,112	21,144
Asset retirement obligations, other provisions and other liabilities	24	87,304	67,978	55,834
Derivative financial instruments	30	3,904	3,386	1,657
<hr/>				
Total non-current liabilities		312,323	271,338	250,932
<hr/>				
<i>Current liabilities</i>				
Trade and other payables	25	93,967	73,720	60,050
Current tax payable		54,296	46,694	40,994
Bonds, bank loans, commercial papers and collateral liabilities	26	19,847	11,730	8,150
Derivative financial instruments	30	3,019	4,161	2,860
<hr/>				
Total current liabilities		171,129	136,305	112,054
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Liabilities directly associated with the assets classified as held for sale	5	0	9,223	0
<hr/>				
Total liabilities		483,452	416,866	362,986
<hr/>				
TOTAL EQUITY AND LIABILITIES		768,607	643,261	563,104

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves		Statoil shareholders' equity	Non- controlling interests	Total equity
							Available for sale financial assets	Currency translation adjustments			
At 31 December 2010	3,188,647,103	7,972	(18)	41,789	(952)	164,935	209	5,607	219,542	6,853	226,395
Net income for the period						78,787			78,787	(344)	78,443
Other comprehensive income						(5,336)	(209)	6,054	509		509
Total comprehensive income for the period											78,952
Dividend paid						(19,891)			(19,891)		(19,891)
Cash distributions (to) from non-controlling interests										(270)	(270)
Equity settled share based payments (net of allocated shares)				36		23			59		59
Treasury shares purchased (net of allocated shares)			(2)		(88)				(90)		(90)
At 31 December 2011	3,188,647,103	7,972	(20)	41,825	(1,040)	218,518	0	11,661	278,916	6,239	285,155

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves		Statoil shareholders' equity	Non- controlling interests	Total equity
							Available for sale financial assets	Currency translation adjustments			
At 31 December 2009	3,188,647,103	7,972	(15)	41,732	(847)	145,909	0	3,568	198,319	1,799	200,118
Net income for the period						38,082			38,082	(435)	37,647
Other comprehensive income						(17)	209	2,039	2,231		2,231
Total comprehensive income for the period											39,878
Dividend paid						(19,095)			(19,095)		(19,095)
Cash distributions (to) from non-controlling interests										5,489	5,489
Equity settled share based payments (net of allocated shares)				57		56			113		113
Treasury shares purchased (net of allocated shares)			(3)		(105)				(108)		(108)
At 31 December 2010	3,188,647,103	7,972	(18)	41,789	(952)	164,935	209	5,607	219,542	6,853	226,395

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves		Statoil shareholders' equity	Non- controlling interests	Total equity
							Available for sale financial assets	Currency translation adjustments			
At 1 January											
2009	3,188,647,103	7,972	(9)	41,450	(586)	147,998	49	17,205	214,079	1,976	216,055
Net income for the period						18,313			18,313	(598)	17,715
Other comprehensive income						2,432	(49)	(13,637)	(11,254)		(11,254)
Total comprehensive income for the period											6,461
Dividend paid						(23,085)			(23,085)		(23,085)
Cash distributions (to) from non-controlling interests										421	421
Merger related adjustments						251			251		251
Equity settled share based payments (net of allocated shares)				282					282		282
Treasury shares purchased (net of allocated shares)			(6)		(261)				(267)		(267)
At 31 December											
2009	3,188,647,103	7,972	(15)	41,732	(847)	145,909	0	3,568	198,319	1,799	200,118

Refer to note 21 *Transactions impacting shareholders equity*.

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	Note	2011	For the year ended 31 December 2010 (restated)	2009 (restated)
OPERATING ACTIVITIES				
Income before tax		213,841	136,826	114,910
<u>Adjustments to reconcile net income to net cash flows provided by operating activities:</u>				
Depreciation, amortisation and impairment losses	13, 14	51,350	50,694	53,830
Exploration expenditures written off		1,531	2,916	6,998
(Gains) losses on foreign currency transactions and balances		4,741	1,539	6,512
(Gains) losses on sales of assets and other items		(27,614)	(1,104)	(256)
<u>Changes in working capital (other than cash and cash equivalents):</u>				
· (Increase) decrease in inventories		(4,102)	(3,431)	(5,045)
· (Increase) decrease in trade and other receivables		(14,366)	(16,705)	10,995
· Increase (decrease) in trade and other payables		20,360	9,521	(1,350)
(Increase) decrease in current financial investments		(8,227)	(4,487)	2,725
(Increase) decrease in net financial derivative instruments	30	(12,786)	(594)	(9,360)
Taxes paid		(112,584)	(92,266)	(100,473)
(Increase) decrease in non-current items related to operating activities		(681)	(2,156)	(6,434)
Cash flows provided by operating activities		111,463	80,753	73,052
INVESTING ACTIVITIES				
Additions through business combinations	5	(25,722)	0	0
Additions to property, plant and equipment		(85,072)	(68,430)	(68,046)
Exploration expenditures capitalised		(6,446)	(3,941)	(7,203)
Additions to other intangibles		(709)	(11,034)	(795)
Change in non-current loans granted and other non-current items		(564)	911	(481)
Proceeds from sale of assets	5	29,843 *	1,909	1,430
Prepayment received related to the held for sale transactions		0	4,124	0
Cash flows used in investing activities		(88,670)	(76,461)	(75,095)

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	Note	For the year ended 31 December		
		2011	2010 (restated)	2009 (restated)
FINANCING ACTIVITIES				
New non-current loans		10,060	15,562	46,318
Repayment of non-current loans		(7,402)	(3,324)	(4,905)
Payment (to)/from non-controlling interests		(275)	5,489 **	421
Dividend paid	21	(19,891)	(19,095)	(23,085)
Treasury shares purchased	21	(408)	(294)	(343)
Net current loans and other		5,161	751	(7,115)
Cash flows provided by (used in) financing activities		(12,755)	(911)	11,291
Net increase (decrease) in cash and cash equivalents		10,038	3,381	9,248
Effect of exchange rate changes on cash and cash equivalents		(316)	450	(2,851)
Cash and cash equivalents at the beginning of the period	20	29,117	25,286	18,889
Cash and cash equivalents at the end of the period	20	38,839	29,117	25,286
Interest paid		3,942	2,591	2,912
Interest received		2,736	2,080	3,962

* Mainly relates to the sale of 40% of the Kai Kos Dehseh oil sands project and 40% of the Peregrino offshore heavy-oil field. Parts of the considerations for these sales were received in 2010. For further information see note 5 *Business development*.

** Including net cash of NOK 5,195 million received from non-controlling interests related to the listing of Statoil's subsidiary Statoil Fuel and Retail ASA as a separate company on the Oslo Stock Exchange on 22 October 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.

Statoil'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 Statoil'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.

Following changes in Statoil's internal organisational structure, the composition of Statoil's reportable segments was changed as of 1 January 2011. For further information see note 4 *Segments* to these financial statements.

The Consolidated financial statements of Statoil for the year ended 31 December 2011 were authorised for issue in accordance with a resolution of the board of directors on 13 March 2012.

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). The accounting policies applied by Statoil 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 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 financial statements.

Standards and interpretations issued but not yet adopted

At the date of these financial statements the following standards and interpretations have been issued but were not yet effective nor adopted by Statoil:

IFRS 9 *Financial Instruments*, issued for the first part in November 2009 and for the second 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. Statoil has not yet determined its adoption date for this standard, and is still evaluating its potential impact.

The amendments to IFRS 7 *Financial Instruments: Disclosures*, issued in October 2010, cover risk exposure related to transfer of assets, will be effective for annual periods beginning after 1 July 2011, and will be implemented by Statoil for the financial year 2012. Statoil does not expect that the amendments to the standard will lead to significant changes in the level of disclosure currently provided, and will comply with the revised standard and provide relevant disclosure upon adoption as applicable.

IFRS 10 *Consolidated Financial Statements*, introduces a new control model that applies to all entities and will require significant management judgement to determine whether an entity is controlled and should be consolidated when there is less than a majority of voting rights, or when there is a loss of control. Statoil is still in the process of determining the potential impact for the financial statements. It is however not expected that the standard will lead to significant changes when it comes to entities deemed to be controlled by Statoil.

IFRS 11 *Joint Arrangements*, introduces a substance over form approach to 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 while joint ventures, where the company has rights to the net assets, will be accounted for using the equity method. Determining which rights a company has in each instance involving a legal entity, and whether its arrangement consequently represents a joint operation or a joint venture, may potentially require considerable management judgement. For activities within the scope of IFRS 11, Statoil has not concluded its review of the joint arrangements that would potentially be accounted for differently under the new standard, but which in the aggregate are not expected to significantly impact Statoil's net income, equity or classifications in the balance sheet or statement of income.

The amendments to IAS 28 *Investments in Associates and Joint Ventures*, reflect changes necessitated by the introduction of IFRS 11, but do not introduce changes to the accounting for investments in associates, which are still to be recognised in accordance with the equity method. Statoil does not expect significant changes to its accounting for investment in associates as a result of implementing the amendments.

IAS 27 *Separate Financial Statements* as amended does not impact the consolidated financial statements.

IFRS 12 *Disclosure of Interests in Other Entities*, introduces disclosure requirements related to interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities following adoption of the requirements in IFRS 10, IFRS 11 and the amendments to IAS 27 and IAS 28. Statoil is in the process of evaluating the standard's requirements and will comply with its requirements and provide the relevant disclosure upon adoption as applicable.

IFRS 10, IFRS 11, IFRS 12, and the amendments to IAS 27 and IAS 28, which all were issued in May 2011, are effective from 1 January 2013 and must be implemented simultaneously and retrospectively in the financial statements upon adoption. Statoil has not yet determined its adoption date for these standards and amendments.

IFRS 13 *Fair Value Measurement*, issued in May 2011, provides guidance on how to measure fair value, but does not introduce changes as to when fair value measurement is to be used in the financial statements. The standard is to be implemented prospectively upon adoption and is effective from 1 January 2013. Statoil is still in the process of evaluating the potential impact of the standard, but does not expect that its implementation will lead to significant changes in the values of assets and liabilities measured at fair value in Statoil's financial statements.

The amendments to IAS 19 *Employee Benefits*, issued in June 2011 and effective from 1 January 2013, replaces interest cost and expected return on plan assets with a net interest amount that is calculated by applying the discount rate to the net defined benefit liability (asset). The difference between the net interest income and the actual return will be recognised in other comprehensive income (OCI). Past service cost will be recognised immediately in the period of a plan amendment and unvested benefits will no longer be spread over a future service period. The amendments moreover enhance disclosure requirements related to pensions and in particular defined benefit plans. Statoil is still in the process of evaluating the amendments' impact for the financial statements, will comply with the revised standard and provide the relevant disclosure as applicable, but has not yet determined its adoption date for the amendments, which are to be implemented retrospectively.

The amendments to IAS 1 *Presentation of Financial Statements*, issued in June 2011, and effective for financial years beginning after 1 July 2012, establish requirements related to presentation and classification of items within OCI, particularly as regards the grouping together of items that may be reclassified to the profit and loss section of the income statement. The amendments do not however introduce changes as to which items should be presented in OCI or which and when items should be recycled through profit or loss. Statoil will comply with the requirements upon adoption, but has not yet determined its adoption date for the amendments.

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. Statoil has not yet determined its adoption date for these amendments, which require retrospective implementation, and is still evaluating their potential impact.

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, effective from 1 January 2013, and further introduce disclosure requirements related to the initial application of IFRS 9 *Financial Instruments* effective at the time of that standard's adoption in the financial statements. Statoil is still in the process of evaluating the impact of the amendments and will provide the relevant disclosure as applicable.

The amendment to IAS 12 *Income Taxes* issued in December 2010 and effective for annual periods beginning 1 January 2012, and IFRIC 20 *Stripping Costs in the Production Phase of a Surface Mine* issued in October 2011 and effective for annual periods beginning 1 January 2013, are currently not relevant for Statoil.

Significant changes in accounting policies in the current period

With effect from 2011 Statoil changed its policy for accounting for jointly controlled entities under IAS 31 *Interests in Joint Ventures*, from application of the equity method to proportionate consolidation. The change has been applied retrospectively in these financial statements including the notes and consequently an opening balance sheet as of 31 December 2009 (1 January 2010) has been included. Prior to 2011 Statoil had limited oil and gas development and production activities organised in jointly controlled legal entities. On the basis of increased materiality of such activities, and with a view to ensuring consistency of the accounting for all jointly controlled oil and gas development and production activities, as well as reasonable compatibility with the new IFRS 11 which is further commented upon above, Statoil concluded that reflecting its share of assets, liabilities, revenues and expenses provides more relevant information concerning this type of activity carried out through jointly controlled entities than including it under the equity method.

Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of Statoil ASA and its subsidiaries. Subsidiaries are entities controlled by Statoil. Control exists when Statoil has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities. Subsidiaries are consolidated from the date of their acquisition, being the date on which Statoil obtains control, and continue to be consolidated until the date that such control ceases.

All intercompany balances and transactions, including unrealised profits and losses arising from group internal transactions, have been eliminated in full. Non-controlling interests (minority interests) represent the portion of profit or loss and net assets in subsidiaries that are not directly or indirectly held by the parent company and 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 balance sheet.

Reportable Segments

Statoil identifies its operating segments on the basis of those components of the Statoil group 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

Functional currency

A group entity's functional currency is the currency of the primary economic environment in which the entity operates.

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 net foreign exchange gains or losses.

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 operating expenses or income tax sections of the Consolidated statement of income depending on the nature of the provision. Non-monetary assets that are measured in terms of 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 balance sheet in functional currency of each entity are translated into the presentation currency, Norwegian kroner (NOK). The assets and liabilities of entities whose functional currencies are other than NOK are translated into NOK at the foreign exchange rate at the balance sheet date. The revenues and expenses of such entities are translated using the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation from functional currency to presentation currency are recognised separately in Other comprehensive income.

Business combinations and goodwill

An acquisition of a business, (an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return directly to investors), is a business combination. Determining whether the 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 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*.

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. The non-controlling interest is measured at fair value or at the proportion of the acquired entity's identifiable net assets as elected for each business combination. Goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination's synergies.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill may also arise upon investments in associates, being the surplus of the cost of investment over Statoil's share of the net fair value of the identifiable assets. Such goodwill is reflected as part of the applicable investment in associates. Any impairment of such goodwill results from an impairment assessment of the investment as a whole, and is reflected in *Net income from associated companies*.

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 has 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 State, are presented net in Statoil's Consolidated financial statements. Sales made by Statoil subsidiaries in their own name, and related expenditure, are however presented gross in Statoil's 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 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 the group. The accounting policies for share-based payments and pension obligations are described below.

Share-based payments

Statoil operates an employee bonus share program. The cost of equity-settled transactions (bonus share awards) with employees is measured by reference to the estimated fair value at the date at which they are granted and is recognised as an expense over the average vesting period of 2.5 years. The awarded shares are accounted for as personnel expenses, and recognised as an equity transaction (included in additional paid-in capital).

Research and development

Statoil undertakes research and development both on a funded basis for license holders, and unfunded projects at its own risk. Statoil's own share of the license holders' funding and the total costs of the unfunded projects are considered for capitalisation.

Development costs which are expected to generate probable future economic benefits are capitalised as intangible assets if, and only if, all of the following have been demonstrated: The technical feasibility of completing the intangible asset so that it will be available for use or sale; the intention to complete the intangible asset and use or sell it; the ability to use or sell the intangible asset; how the intangible asset will generate probable future economic benefits; the availability of adequate technical, financial and other resources to complete the development and to use or sell the intangible asset, and the ability to reliably measure the expenditure attributable to the intangible asset during its development. All other research and development expenditure is expensed as incurred.

Subsequent to initial recognition, capitalised development costs are reported at cost less accumulated amortisation and accumulated impairment losses.

Income tax

Income tax in the Consolidated statement of income for the year comprises current and deferred tax expense. Income tax is recognised in the Consolidated statement of income except to the extent that it relates to items recognised in Other comprehensive income.

Current tax is the expected tax payable on the taxable income for the year and any adjustment to tax payable in respect of 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 as 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 in the financial statements and their respective tax bases, subject to the initial recognition exemption. The amount of deferred tax provided 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 special petroleum tax is levied on profits derived 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 the standard 28% income tax, resulting in a 78% marginal tax rate on income subject to Norwegian 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 against the special petroleum tax, and a tax-free allowance, or uplift, which 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. 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 expenditure

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 expenditure within intangible assets until the well is complete and the results have been evaluated. If, following evaluation, the exploratory well has not found proved reserves, the previously capitalised costs are evaluated for de-recognition 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 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.

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. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present. Impairment and reversals of impairment of exploration and evaluation assets are charged to *Exploration expenses* in the Consolidated statement of income.

Capitalised exploration and evaluation expenditure, including expenditures to acquire mineral interests in oil and gas properties, related to wells that find proved reserves are transferred from Exploration expenditure (*Intangible assets*) to Assets under development (*Property, plant and equipment*) at the time of sanctioning of the development project.

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 also include assets acquired under the terms of profit sharing agreements (PSAs) in certain countries, and which qualify for recognition as assets of the group. 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 the group, the expenditure is capitalised. Inspection and overhaul costs associated with major maintenance programs are capitalised and amortised over the period to the next inspection. All other maintenance costs are expensed as incurred.

Capitalised exploration and evaluation expenditure, 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 cost is 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 (E&P) 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 de-recognition 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.

Non-current assets 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. Property, plant and equipment and intangible assets once classified as held for sale 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 in terms of which Statoil assumes substantially all the risks and rewards of the ownership are reflected as finance leases within *Property, plant and equipment* and *Bonds, bank loans and finance lease liabilities*. Assets under development for finance lease purposes, and for which Statoil carries substantially all the risk in the construction period, are reflected as finance leases under development within *Property, plant and equipment* based on the stage of completion at period end, unless another amount better reflects the realities of the arrangement. All other leases are classified as operating leases and the costs are charged to operating expenses on a straight line basis over the lease term, unless another basis is more representative of the benefits of the lease to the group.

Finance lease assets are reflected at an amount equal to the lower of fair value and the present value of the minimum lease payments at inception of the lease, and subsequently reduced by accumulated depreciation and impairment losses, if any. 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 in the Consolidated balance sheet as *Property, plant and equipment* and *Bonds, bank loans and finance lease liabilities*, respectively. Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term using the depreciation methods described under "Property, plant and equipment" above, depending on the nature of the leased asset.

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 capacity volume 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

Intangible assets are stated at cost, less accumulated amortisation and accumulated impairment losses. Intangible assets include expenditure on the exploration for and evaluation of oil and natural gas resources, goodwill and other intangible assets. Intangible assets acquired separately from a business are carried initially at cost. An intangible asset acquired as part of a business combination is recognised separately from goodwill at its fair value if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

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 on this under "Oil and gas exploration and development expenditure".

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. Such assets are subject to impairment testing when facts and circumstances suggest that the carrying amount of an asset may exceed its recoverable amount (or at least on an annual basis), and are reclassified to property, plant and equipment when the decision to develop a particular area is made.

Other intangible assets are amortised on a straight-line basis over their expected useful lives. The expected useful lives of the assets are reviewed on an annual basis and changes in useful lives are accounted for prospectively.

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 the group classifies its financial assets into the following three main categories; financial instruments at fair value through profit or loss; loans and receivables; and available-for-sale (AFS) financial assets. The first main category, financial instruments 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".

Financial assets classified in the loans and receivables category are carried at amortised cost using the effective interest method. Gains and losses are recognised in the statement of income when the loans and receivables are derecognised or impaired, while amortisation is reflected over the term of each loan or receivable in the statement of income under Interest income and other financial items. Trade and other 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.

Financial assets classified as AFS mainly include non-listed equity instruments. AFS equity instruments are carried at fair value in the balance sheet, with the change in fair value recognised directly in Other comprehensive income until the investment is derecognised or until the investment is determined to be impaired, at which time the cumulative change in fair value previously reported in Other comprehensive income is recognised in the statement of income.

A significant part of Statoil's investments in commercial papers, bonds and listed equity securities are managed together as an investment portfolio of the group's captive insurance company and are 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.

Current financial investments are initially recognised in the category financial instruments at fair value through profit or loss, either as held for trading or through the Statoil's application of the fair value option. Following from that classification the current financial investments are carried in the balance sheet at fair value with changes in their fair values recognised in the statement of income.

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. Other financial assets expected to be recovered more than 12 months after the balance sheet date and for which there is no plan of realisation are classified as non-current.

Financial assets are derecognised when the contractual rights to the cash flows expire or substantially all risks and rewards related to the ownership of the financial asset are transferred to a third party.

Financial assets and financial liabilities are shown separately in the 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 takes place and is reflected within *Trade and other receivables* and *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 intangible assets with finite useful lives and property, plant and equipment

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 capitalised exploration expenditure, the cash-generating units are individual wells.

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 flow generating assets, set down in Statoil's most recently approved long term plans. Statoil's long term plans are approved 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 also include project or asset specific estimates established in line with group consistent assumptions and principles.

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 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.

If assets are determined to be impaired, the carrying amounts of those assets are written down to the recoverable amount which is the higher of fair value less costs to sell and value in use.

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 as *Exploration expenses* or *Depreciation, amortisation and net impairment losses* respectively, 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).

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. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the business combination's synergies.

Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognised, firstly on goodwill and then pro-rata on the other assets of that unit. Impairments of goodwill once recognised are not reversed in future periods.

Impairment of financial assets

Statoil assesses at each balance sheet date whether a financial asset or group of financial assets is impaired, except for the financial assets classified in the fair value through profit and loss category.

If there is objective evidence that an impairment loss has been incurred for assets carried at amortised cost, the carrying amount of the asset is reduced by the amount of the loss recognised in the statement of income. Any subsequent reversal of an impairment loss is correspondingly also recognised in the statement of income.

If an AFS financial asset is impaired, that is a decline in the fair value of an equity instrument has been assessed to be significant or prolonged, the difference between cost and fair value is transferred from Other comprehensive income to the Consolidated statement of income. When impairments of equity instruments classified as AFS are reversed this is recognised directly in Other comprehensive income.

Financial liabilities

Financial liabilities are initially recognised at fair value when Statoil becomes a party to the contractual provisions of the liability. For additional information on fair value methods, refer to the "Measurement of fair values" section below. The subsequent measurement of financial liabilities depends on which category they have been classified into. The categories applicable for Statoil is 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.

Trade and other payables are carried at payment or settlement amounts.

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. Other financial liabilities which contractually will be settled more than 12 months after the balance sheet date are classified as non-current.

Financial liabilities are derecognised when the contractual obligation expires, is 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.

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 for all significant purposes are related to sales contracts or revenue related risk management. 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 continued 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 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 subject of 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. Contracts are assessed for embedded derivatives when Statoil becomes a party to them, including at the date of a business combination. Such embedded derivatives are measured at fair value at each period end, and the changes in fair value are recognised in profit or loss for the period.

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 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 the group's obligations and established on the basis of 10-years' Norwegian government bonds for the main part of the pension obligations, as there is no sufficiently deep market in high quality corporate bonds in Norway. The calculation is performed by an external actuary. Current service cost is an element of net periodic pension cost and recognised in the statement of income.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and 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. Due to the parent company Statoil ASA's functional currency being USD, the significant part of the group's pension obligations will be payable in a foreign currency (i.e. NOK). Actuarial gains and losses related to the parent company's pension obligation as a consequence 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.

Provisions and contingent assets and liabilities

Provisions are recognised when Statoil has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as other finance expenses.

Contingent liabilities arising from past events and for which it is not probable that an outflow of resources will be required to settle the obligation, if any, are not recognised but disclosed with indication of uncertainties relating to amounts and timing involved, unless the possibility of an outflow in settlement is remote.

Possible assets arising from past events that will only be confirmed by future uncertain events and are not wholly within Statoil's control (contingent assets), are not recognised, but are disclosed when an inflow of economic benefits is probable. The asset and related income are subsequently recognised in the Consolidated financial statements in the period in which the inflow of economic benefits becomes virtually certain.

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. Cost is estimated upon current regulation and technology, considering relevant risks and uncertainties, to arrive at best estimates. 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 for ARO may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The provision is classified under *Asset retirement obligations, other provisions and other liabilities* in the balance sheet. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. Refining and processing plants that are not limited by licence periods are deemed to have indefinite lives and in consequence no asset retirement obligation has been recognised. For retail outlets, ARO provisions are estimated on a portfolio basis.

When a provision for ARO cost is recognised, a corresponding amount is recognised to increase the related property, plant and equipment. This 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.

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.

A financial instrument is regarded as quoted in an active market if the prices quoted are readily and regularly available, normally through an exchange, and the prices quoted by the exchange represent actual and regularly occurring market transactions that are identical to the instrument being valued. Statoil considers both the actual volume and the timing of recent market transactions in determining whether prices are quoted in a sufficiently active market. 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 quotations 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 goods 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 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. This conflict has in 2011 been referred to the IASB by the IFRS Interpretations Committee to be resolved as part of a broader project on equity accounting. 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. In making this judgment, Statoil considered which guidance best reflects the substance of such transactions, and concluded that the substance is the formation of joint ventures and that the accounting treatment that best reflects the economics of the transactions would be to follow the guidance of IAS 31/SIC 13 which provides the most understandable and relevant representation of these transactions.

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, 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 have been estimated by internal experts 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. 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 hydrocarbons volumes, the production, historical extraction 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 such evaluation do not differ materially from management estimates (excluding the Brigham reserves estimates which were prepared by another third party). 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. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates used for depreciation and amortisation.

Expected oil and gas reserves. 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, which should 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. Expected oil and gas reserves have been estimated by internal experts 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 hydrocarbons volumes, the production, historical extraction 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. Future changes in expected oil and gas reserves, for instance as a result of changes in prices, could have a material impact on asset retirement obligations, as well as for the impairment testing of upstream assets, which could have a material effect on operating income as a result of changed impairment charges.

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. Judgments 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, and 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 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 pension benefit 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. Legal and constructive obligations associated with the retirement of non-current assets are recognised at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is capitalised as part of the related non-current asset and allocated to expense over the useful life of the asset.

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. 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. Statoil annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also 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 Accounting policy change for jointly controlled entities

As stated in note 2 *Significant accounting policies*, Statoil changed its policy for accounting for jointly controlled entities under IAS 31 *Interests in Joint Ventures*, from application of the equity method to proportionate consolidation with effect from 2011. Proportionate consolidation has been retrospectively applied in the Consolidated financial statements and the following tables show the effect of the change for year 2010 and 2009. All the restated comparable figures are also presented in the relevant notes. The accounting policy change has no effect on net income, earnings per share, or shareholder's equity or non-controlling interests.

CONSOLIDATED STATEMENT OF INCOME

(in NOK million)	2010			2009		
	For the year ended 31 December (as reported)	Restatement	For the year ended 31 December (as restated)	For the year ended 31 December (as reported)	Restatement	For the year ended 31 December (as restated)
REVENUES AND OTHER INCOME						
Revenues	526,718	232	526,950	462,292	227	462,519
Net income from associated companies	1,133	35	1,168	1,778	(321)	1,457
Other income	1,797		1,797	1,363	11	1,374
Total revenues and other income	529,648	267	529,915	465,433	(83)	465,350
OPERATING EXPENSES						
Purchases [net of inventory variation]	(257,427)	(9)	(257,436)	(205,870)		(205,870)
Operating expenses	(57,531)	(139)	(57,670)	(56,860)	(114)	(56,974)
Selling, general and administrative expenses	(11,081)		(11,081)	(10,321)		(10,321)
Depreciation, amortisation and net impairment losses	(50,608)	(86)	(50,694)	(54,056)	226	(53,830)
Exploration expenses	(15,773)		(15,773)	(16,686)		(16,686)
Total operating expenses	(392,420)	(234)	(392,654)	(343,793)	112	(343,681)
Net operating income	137,228	33	137,261	121,640	29	121,669
FINANCIAL ITEMS						
Net foreign exchange gains (losses)	(1,836)	10	(1,826)	1,993	(4)	1,989
Interest income and other financial items	3,175	(62)	3,113	3,708		3,708
Interest and other finance expenses	(1,751)	29	(1,722)	(12,451)	(5)	(12,456)
Net financial items	(412)	(23)	(435)	(6,750)	(9)	(6,759)
Income before tax	136,816	10	136,826	114,890	20	114,910
Income tax	(99,169)	(10)	(99,179)	(97,175)	(20)	(97,195)
Net income	37,647		37,647	17,715		17,715

CONSOLIDATED BALANCE SHEET

(in NOK million)	2010			2009		
	At 31 December (as reported)	Restatement	At 31 December (as restated)	At 31 December (as reported)	Restatement	At 31 December (as restated)
ASSETS						
<i>Non-current assets</i>						
Property, plant and equipment	348,204	3,374	351,578	340,835	1,685	342,520
Intangible assets	39,695	3,476	43,171	54,253	91	54,344
Investments in associated companies	13,884	(4,887)	8,997	10,056	(632)	9,424
Deferred tax assets	1,878		1,878	1,960		1,960
Pension assets	5,265		5,265	2,694		2,694
Derivative financial instruments	20,563		20,563	17,644		17,644
Financial investments	15,357		15,357	13,267		13,267
Prepayments and financial receivables	4,510	(565)	3,945	5,747	(1,540)	4,207
Total non-current assets	449,356	1,398	450,754	446,456	(396)	446,060
<i>Current assets</i>						
Inventories	23,627		23,627	20,196		20,196
Trade and other receivables	76,139	(1,329)	74,810	58,895	97	58,992
Current tax receivables	1,076		1,076	179		179
Derivative financial instruments	6,074		6,074	5,369		5,369
Financial investments	11,509		11,509	7,022		7,022
Cash and cash equivalents	30,337	184	30,521	24,723	563	25,286
Total current assets	148,762	(1,145)	147,617	116,384	660	117,044
Assets classified as held for sale	44,890		44,890			
TOTAL ASSETS	643,008	253	643,261	562,840	264	563,104

CONSOLIDATED BALANCE SHEET

(in NOK million)	2010			2009		
	At 31 December (as reported)	Restatement	At 31 December (as restated)	At 31 December (as reported)	Restatement	At 31 December (as restated)
EQUITY AND LIABILITIES						
<i>Equity</i>						
Share capital	7,972		7,972	7,972		7,972
Treasury shares	(18)		(18)	(15)		(15)
Additional paid-in capital	41,789		41,789	41,732		41,732
Additional paid-in capital related to treasury shares	(952)		(952)	(847)		(847)
Retained earnings	164,935		164,935	145,909		145,909
Other reserves	5,816		5,816	3,568		3,568
Statoil shareholders' equity	219,542		219,542	198,319		198,319
Non-controlling interests	6,853		6,853	1,799		1,799
Total equity	226,395		226,395	200,118		200,118
<i>Non-current liabilities</i>						
Bonds, bank loans and finance lease liabilities	99,797		99,797	95,962		95,962
Deferred tax liabilities	78,052	13	78,065	76,322	13	76,335
Pension liabilities	22,110	2	22,112	21,142	2	21,144
Asset retirement obligations, other provisions and other liabilities	67,910	68	67,978	55,834		55,834
Derivative financial instruments	3,386		3,386	1,657		1,657
Total non-current liabilities	271,255	83	271,338	250,917	15	250,932
<i>Current liabilities</i>						
Trade and other payables	73,551	169	73,720	59,801	249	60,050
Current tax payable	46,693	1	46,694	40,994		40,994
Bonds, bank loans, commercial papers and collateral liabilities	11,730		11,730	8,150		8,150
Derivative financial instruments	4,161		4,161	2,860		2,860
Total current liabilities	136,135	170	136,305	111,805	249	112,054
Liabilities directly associated with the assets classified as held for sale	9,223		9,223			
Total liabilities	416,613	253	416,866	362,722	264	362,986
TOTAL EQUITY AND LIABILITIES	643,008	253	643,261	562,840	264	563,104

As at 31 December 2009, the jointly controlled entities for which the restatements relate were Naturkraft AS (50%) and Scira Offshore Energy Limited (50%). As at 31 December 2010, the restatements also included a part of the Eagle Ford shale formation in Southwest Texas, which was temporarily organised as a jointly controlled entity, but subsequently dissolved and organised as an unincorporated joint venture.

As at 31 December 2011, the main jointly controlled entities are the Kai Kos Dehseh Oil Sands Partnership (60%), South Atlantic Holding BV (60%), Naturkraft AS (50%) and Scira Offshore Energy Limited (50%).

Internal transactions between the jointly controlled entities and other consolidated entities are eliminated based on Statoil's ownership interests.

8.1.4 Segments

Operating segments

The composition of Statoil's reportable segments has changed on the basis of the new corporate structure implemented with effect from 1 January 2011. Comparable periods have been restated accordingly.

Statoil's operations are managed through the following operating segments; Development and Production Norway (DPN; previously Exploration and Production Norway); Development and Production North America (DPNA; previously included in International Exploration and Production); Development and Production International (DPI; previously International Exploration and Production); Marketing Processing and Renewable Energy (MPR; previously Natural Gas, Manufacturing and Marketing and parts of Technology and New energy which were included in the Other segment); Fuel and Retail (FR) and Other.

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 United States of America and Canada, and DPI worldwide outside of North America and Norway.

Exploration activities are managed by a separate business unit, which has the global responsibility across the group for discovery and appraisal of new resources. Exploration activities are allocated to and presented in the respective Development and Production segments.

The MPR segment is responsible for marketing and trading of oil and gas commodities (crude, condensate, gas liquids, products, natural gas and LNG), 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.

The FR segment markets fuel and related products principally to retail consumers.

The Other reporting segment includes activities within Global Strategy and Development, Technology, Projects and Drilling and the Corporate Centre, and Corporate 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 into one reporting segment has its basis in similar economic characteristics, the nature of products, services and production processes, as well as 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.

The measurement basis of segment profit is *Net operating income*. Financial items, tax expense and tax assets are not allocated to the operating segments.

Segment data for the years ended 31 December 2011, 2010 and 2009 is presented below:

(in NOK million)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2011							
Revenues third party and Other income	7,861	25,158	564,139	70,779	1,004	0	668,941
Revenues inter-segment	204,181	44,810	45,674	2,904	1	(297,570)	0
Net income (loss) from associated companies	60	953	163	3	85	0	1,264
Total revenues and other income	212,102	70,921	609,976	73,686	1,090	(297,570)	670,205
Net operating income	152,713	32,821	24,743	1,869	(256)	(106)	211,784
Significant non-cash items recognised in segment profit or loss							
- Depreciation and amortisation	29,577	15,933	2,762	1,169	759	0	50,200
- Net impairment losses (reversals)	0	(2,098)	3,248	0	0	0	1,150
- Unrealised (gain) loss on commodity derivatives	(5,580)	(12)	(3,629)	0	0	0	(9,221)
- Exploration expenditure written off	1,064	467	0	0	0	0	1,531
Investments in associated companies	153	5,529	2,684	49	802	0	9,217
Other segment non-current assets*	211,632	239,378	34,443	10,814	3,992	0	500,259
Assets classified as held for sale	0	0	0	0	0	0	0
Non-current assets, not allocated to segments*							61,043
Total non-current assets and assets classified as held for sale							570,519
Additions to PP&E and intangible assets**	41,490	84,339	4,716	1,479	1,590		133,614

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligations.

(in NOK million)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2010							
Revenues third party and Other income	4,101	8,367	452,613	62,283	1,383	0	528,747
Revenues inter-segment	166,571	41,930	40,509	3,571	2,213	(254,794)	0
Net income (loss) from associated companies	56	703	469	4	(64)	0	1,168
Total revenues and other income	170,728	51,000	493,591	65,858	3,532	(254,794)	529,915
Net operating income	115,615	12,624	6,125	2,354	615	(72)	137,261
Significant non-cash items recognised in segment profit or loss							
- Depreciation and amortisation	26,020	15,184	3,021	1,215	683	0	46,123
- Net impairment losses (reversals)	0	1,469	2,995	97	10	0	4,571
- Unrealised (gain) loss on commodity derivatives	(1,866)	0	4,316	0	0	0	2,450
- Exploration expenditure written off	1,441	1,470	0	0	0	0	2,911
Investments in associated companies	133	5,066	3,603	43	152	0	8,997
Other segment non-current assets*	188,196	137,320	55,161	11,113	2,959	0	394,749
Assets classified as held for sale	0	44,890	0	0	0	0	44,890
Non-current assets, not allocated to segments*							47,008
Total non-current assets and assets classified as held for sale							495,644
Additions to PP&E and intangible assets**	31,902	44,221	7,723	829	949		85,624

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligations.

(in NOK million)	Development and Production Norway	Development and Production International	Marketing, Processing and Renewable Energy	Fuel and Retail	Other	Eliminations	Total
Year ended 31 December 2009							
Revenues third party and Other income	4,153	12,301	390,537	55,951	951	0	463,893
Revenues inter-segment	154,431	28,460	31,818	1,405	2,318	(218,432)	0
Net income (loss) from associated companies	79	1,075	336	27	(60)	0	1,457
Total revenues and other income	158,663	41,836	422,691	57,383	3,209	(218,432)	465,350
Net operating income	104,318	2,602	16,288	1,269	(729)	(2,079)	121,669
Significant non-cash items recognised in segment profit or loss							
- Depreciation and amortisation	25,534	16,231	3,021	1,212	667	0	46,665
- Net impairment losses (reversals)	119	873	6,161	0	12	0	7,165
- Unrealised (gain) loss on commodity derivatives	(1,958)	0	(2,188)	0	(42)	0	(4,188)
- Exploration expenditure written off	1,177	5,821	0	0	0	0	6,998
Investments in associated companies	214	4,962	3,650	235	363	0	9,424
Other segment non-current assets*	175,997	152,679	53,578	11,773	2,837	0	396,864
Assets classified as held for sale	0	0	0	0	0	0	0
Non-current assets, not allocated to segments*							39,772
Total non-current assets and assets classified as held for sale							446,060
Additions to PP&E and intangible assets**	34,875	39,354	7,558	2,608	1,320		85,715

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in asset retirement obligations.

See note 13 *Property, plant and equipment* and note 14 *Intangible assets* for information on impairments recognised in the DPI segment and in the MPR segment.

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

Geographical areas

Statoil has business operations in 41 countries, and manages its business segments on a worldwide basis. In presenting information on the basis of geographical areas, revenues from external customers are attributed to the country of the legal entity executing the external sale.

Assets are based on the geographical location of the assets.

Geographical data for the year ended 31 December 2011, 2010 and 2009 is presented below:

(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2011						
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
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(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2010						
Norway	227,122	72,643	47,551	47,332	16,947	411,595
USA	22,397	7,817	1,815	14,918	5,781	52,728
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	2,457	23,700

Total revenues (excluding net income (loss) from associated companies)	254,027	84,840	49,571	107,485	32,824	528,747
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(In NOK million)	Crude Oil	Gas	NGL	Refined Products	Other	Total Sale
Year ended 31 December 2009						
Norway	182,353	80,018	34,655	45,927	18,375	361,328
USA	19,836	5,555	117	14,017	672	40,197
Sweden	0	0	0	16,556	3,795	20,351
Denmark	0	0	0	15,105	1,957	17,062
Other	9,978	2,959	154	10,762	1,102	24,955

Total revenues (excluding net income (loss) from associated companies)	212,167	88,532	34,926	102,367	25,901	463,893
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Assets by geographic areas

(in NOK million)	2011	2010	2009
Norway	249,184	239,989	228,857
USA	112,552	53,694	38,993
Angola	43,624	29,050	23,345
Brazil	25,979	37,008	29,549
Azerbaijan	17,760	17,296	17,331
Canada	17,307	24,495	20,553
Algeria	9,614	9,308	9,265
Other areas	33,456	37,796	38,395

Total non-current assets (excluding deferred tax assets, pension assets and financial non-current items) and assets classified as held for sale at 31 December	509,476	448,636	406,288
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Major customers

Statoil does not have transactions with single external customers where revenues amount to more than 10% of the group's total revenues.

8.1.5 Business development

Business combinations

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 for USD 36.50 per share through an all-cash tender offer. Brigham was listed on the NASDAQ in the United States (US).

Statoil obtained control over Brigham on 1 December 2011, which is 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 billion, including NOK 4.6 billion related to the purchase of the non-controlling interest in December 2011. Statoil elected to measure the non-controlling interest in the acquiree at acquisition date fair value (USD 36.50 per share). There was no gain or loss on the subsequent acquisition of the non-controlling interest.

Brigham was an independent exploration, development and production company. It utilises advanced exploration, drilling and completion technologies to systematically explore for, develop and produce 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 objectives in North Dakota and Montana.

The acquisition has been accounted for using the acquisition method, where the acquired assets and liabilities have been measured at fair value at the date of acquisition and it has been recognised in the Development and Production International segment. The Consolidated financial statements include results of Brigham for the one-month period from the acquisition date. The table below provide an overview of the fair value of the identifiable assets and liabilities of Brigham as at the date of the acquisition.

FAIR VALUE RECOGNISED ON ACQUISITION DATE

(in NOK million)	At 1 December 2011
ASSETS	
Property, plant and equipment	7,514
Intangible assets	24,056
Deferred tax assets	857
Trade and other receivables	1,387
Cash and cash equivalents	268
Other assets	243
TOTAL ASSETS	34,325
LIABILITIES	
Bonds, bank loans, commercial papers and collateral liabilities	4,068
Deferred tax liabilities	8,744
Trade and other payables	2,234
Other liabilities	156
TOTAL LIABILITIES	15,202
Total identifiable net assets at fair value	19,123
Goodwill arising on acquisition	6,867
Total cost of acquisition	25,990
Non-controlling interests	4,638
Net cash and cash equivalent acquired with the subsidiary	268
Cash paid, including for non-controlling interests	(25,990)
Net cash outflow	(25,722)

From the date of the acquisition, Brigham has contributed NOK 465 million of revenues and NOK 35 million to the *Net income* of Statoil in 2011. If the combination had taken place at the beginning of the year, Brigham would have contributed NOK 3.0 billion of revenues and NOK 0.9 billion to the *Net income* of Statoil in 2011.

The goodwill of NOK 6.9 billion recognised from the transaction has been attributed to Statoil's US onshore operations on the basis of expected synergies and other benefits to the group from Brigham's assets and activities. The goodwill will not be deductible for tax purposes. The identified intangible assets (in addition to the goodwill amount) relate in their entirety to exploration assets.

Transaction costs of NOK 0.2 billion have been expensed and are included in *Selling, general and administrative expenses* in the Consolidated statement of income and are part of the operating cash flows in the Consolidated statement of cash flows.

Contingent consideration from Peregrino acquisition

In the fourth quarter of 2011, Statoil has settled the contingent element of the consideration agreed as part of the acquisition of a 50% working interest in the Peregrino offshore heavy-oil field in Brazil from Anadarko in 2008. The settlement amount was NOK 2.5 billion, which was equal to the maximum amount in the agreed range, including accrued interest. The settlement did not significantly impact the Consolidated statement of income.

Asset acquisitions

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 USD 1.4 billion, which include signature bonuses and minimum work commitments for all the blocks. As at 31 December 2011 a total of NOK 5.2 billion has been recognised in the Development and Production International segment and presented as *Intangible assets*.

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 rights 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 USD 0.9 billion. The transaction was completed on 8 December 2010 and has been recognised in the Development and Production International segment.

Disposals

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 is principally subject to the tax exemption rules in the Norwegian Petroleum Tax system, however, a portion is taxable under the ordinary Norwegian tax system. Statoil has recognised a pre-tax gain of NOK 8.4 billion from the transaction in the fourth quarter of 2011, which includes a release of deferred tax liabilities related to the tax exempted portion of the transaction. The transaction has been recognised in the Marketing, Processing and Renewable Energy segment and presented as *Other income*.

Agreement to sell interests in exploration and production licenses on the Norwegian continental shelf

On 21 November 2011 Statoil entered into an agreement with Centrica Resources (Norway) AS and Centrica Norway Limited (Centrica) to sell its ownership interests in the Skirre- Byggve (10%), Fulla (50%), Frigg-Gamma-Delta (40%), Vale (28.9%) and Rind (37.9%) licences on the Norwegian continental shelf (NCS). In the same agreement a partial divestment has been agreed where Statoil sells a 19% interest in the Kvitebjørn licence, 10% in the Heimdal licence and 13% in the Valemon licence.

Centrica will pay a post-tax consideration of USD 1.5 billion plus a contingent consideration of up to USD 0.1 billion. The transaction is subject to approvals from the Norwegian Ministry of Petroleum and Energy and the Norwegian Ministry of Finance. Statoil will continue to consolidate the proportional share (current ownership share) of the revenues and expenditures until the date of closing of the transaction. The transaction will be recognised in the Development and Production Norway segment at the time of closing, which is expected in second quarter of 2012. As at 31 December 2011, the book value of the assets and liabilities subject to the transaction has not been considered significant enough to be classified as held for sale in the Consolidated balance sheet.

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. See note 3 *Accounting policy change for jointly controlled entities* for more information.

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 Development and Production International segment in the first quarter of 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 control the Peregrino assets. Statoil remains 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 (see note 2 *Significant accounting policies*) and presented as *Other income*. The transaction was recognised in the Development and Production International segment in the second quarter of 2011.

Assets classified as held for sale

The table below shows a specification of assets and liabilities classified as held for sale:

(in NOK million)	At 31 December 2011	At 31 December 2010	At 31 December 2009
Property plant and equipment	0	32,515	0
Intangible assets	0	12,375	0
Total assets classified as held for sale	0	44,890	0
Bonds, bank loans and finance lease liabilities	0	7,796	0
Asset retirement obligation, other provisions and other liabilities	0	549	0
Bonds, bank loans, commercial papers and collateral liabilities	0	878	0
Total liabilities directly associated with the assets classified as held for sale	0	9,223	0

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 Capital management

Capital management

The objective of Statoil's capital management policy is to maximise value creation over time, while maintaining a strong financial position and long-term credit ratings at least within the single A category.

Management makes regular use of Funds from operations over Net adjusted debt (FFO/ND) and Net adjusted debt over Capital employed (ND/CE) ratios in its assessment of Statoil's financial flexibility and ability to incur additional debt.

FFO is net operating cash flows provided by operating activities adjusted for certain items employed by major rating agencies. These items include cash effects from operating leases, post retirement benefit obligations, capitalised interest, asset retirement obligations and reclassifications of working capital cash flows.

ND in this respect is defined as Statoil's current and non-current financial liabilities adjusted for Statoil's liquidity positions and adjusted for the items defined above. In addition certain adjustments are made through the addition of project financing, balances related to the SDFI, and balances held by the group's captive insurance company.

CE is Statoil's total equity (including non-controlling interest) plus net interest bearing debt, including debt adjustments defined above.

Credit rating

Credit rating is important to Statoil in order to provide necessary financial flexibility to support a dynamic strategy through economic-and market cycles. Statoil has credit ratings from Moody's and Standard & Poor's and the stated objective is to have credit ratings at least within the single A category. This rating ensures necessary predictability when it comes to funding access to relevant capital markets at favourable terms and conditions. We have the intention to maintain financial ratios that we consider adequate for maintaining credit ratings at levels consistent with the rating target.

Funding of subsidiaries, associates and jointly controlled entities

Normally the parent company, Statoil ASA, incurs debt and then extends loans or equity to wholly owned subsidiaries to fund capital requirements within the group. Statoil Petroleum AS is co-obligor or guarantor of existing debt securities and other loan arrangements of Statoil ASA. As co-obligor, Statoil Petroleum AS assumes and agrees to perform, jointly and severally with Statoil ASA, all payment and covenant obligations for this debt.

When partially owned subsidiaries or investments in associates and jointly controlled entities are financed, it is Statoil's policy to finance according to ownership share and on equal terms with the other owners. Statoil ASA does not extend loans to the Statoil Fuel & Retail subgroup (SFR). The SFR subgroup raises debt in the external market to fund its capital requirements within the SFR group. All terms for financing of subsidiaries, associates and jointly controlled entities are based on arm's-length principles. Project specific financing may also be used with the primary objective to mitigate risk.

Capital distribution

Capital distribution consists of dividend payments and share buy-backs. Present dividend policy states:

"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, Statoil will take into consideration expected cash flows, capital expenditure plans, financing requirements and appropriate financial flexibility. In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders."

The dividend policy has no direct link to the reported net income, and the focus will be on growing the annual cash dividend per share in line with long-term underlying earnings. Statoil emphasises the importance of maintaining competitive direct shareholder return, cash dividends and potential share repurchases.

8.1.7 Financial risk management

General information relevant to financial risks

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. 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 have overestimated 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 the company.

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 for Statoil.

Financial risks

Statoil's activities expose the group to the following financial risks as defined by IFRS 7:

- Market risk (including commodity price risk, currency risk, interest rate risk and equity price 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 the group 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 the group's Corporate risk committee.

The group has established guidelines for entering into derivative contracts in order to manage our commodity price, foreign currency rate, and interest rate risks. The group 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 31 *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, the group 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 31 *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, the NOK, EUR and GBP, against the 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 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, the group's currency management is primarily linked to secure tax and dividend payments in NOK. This means that the group regularly purchase substantial NOK amounts on a forward basis using conventional derivative instruments.

Interest rate risk

Statoil aims to diversify sources of funding, and to achieve lower expected funding costs over time. By issuing both fixed interest rate debt and floating interest rate debt, Statoil's funding sources become more diversified through reaching a broader spectrum of bond investors.

With regards to interest rate risk, Statoil manages the group's 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.

Bonds are normally issued at fixed rates in a variety of local currencies (among others JPY, EUR, CHF, GBP and USD). These bonds are converted to floating USD bonds by using interest rate- and currency swaps. For more detailed information about the group's long-term debt-portfolio see note 22 *Bonds, bank loans and finance lease liabilities*.

Equity price risk

Statoil's captive insurance company holds listed equity securities as a part of its portfolio. In addition, Statoil holds some other non-listed equity securities for long-term strategic purposes. By holding these assets Statoil is exposed to equity price risk, defined as the risk of declining equity prices, which can result in a decline in the carrying value of the group's assets recognised in the balance sheet. The equity price risk in the portfolio held by Statoil's captive insurance company is managed, with the aim of maintaining a moderate risk profile, through geographical diversification and the use of broad benchmark indexes. For more information about the group's equity securities see note 16 *Non-current financial assets and prepayments* and note 19 *Current financial investments*.

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 and current liability 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 group 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 maintain 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 2011 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 US Commercial Papers Programme (CP), USD 4 billion which is backed by a revolving credit facility of USD 3 billion, supported by 20 core banks. The facility is undrawn and provides secure access to funding, supported by best available short-term rating. The credit facility had a term of four years until December 2015, but includes two one year extension options which may extend the facility to December 2017. Statoil has exercised the first 1 year option and extended the maturity to December 2016. The facility agreement does not contain any repeating material adverse change clauses, or any financial covenants. Statoil Petroleum AS is guarantor of the facility.

On 1 November 2010 Statoil Fuel & Retail ASA drew down NOK 4 billion on its term loan facility, maturing in October 2013. The facility is part of a multicurrency term and revolving loan facility in the aggregate amount of NOK 7 billion, which has been entered into with nine international banks. In addition to the NOK 4 billion three year term loan already drawn, the total facility agreement includes a NOK 3 billion five year revolving loan facility. Of this facility NOK 0.2 billion was drawn at end December 2011.

Statoil raises debt in all major capital markets (USA, Europe and Japan) for long-term funding purposes. In order to comply with the group's financial policies, Statoil uses derivatives such as currency and interest rate swaps to convert cash flows into floating rate USD interest payments. The policy is to have a smooth maturity profile with repayments not exceeding five percent of capital employed in any year for the nearest five years. Statoil's non-current financial liability has an average maturity of approximately nine years.

For more information about the group's non-current financial liabilities see note 22 *Bonds, bank loans and finance lease liabilities*.

The table below shows a maturity profile, based on undiscounted contractual cash flows, for the financial liabilities and financial assets held to manage liquidity risk, where the assets held by Statoil's captive insurance company have been excluded. Included in the assets held to manage liquidity risk are certain foreign currency derivative instruments.

(in NOK million)	Due within 1 year	Due between 1 and 2 years	Due between 3 and 4 years	Due between 5 and 10 years	Due after 10 years	Total specified
At 31 December 2011						
Non-derivative financial liabilities	(109,507)	(31,651)	(32,134)	(47,179)	(55,093)	(275,564)
Derivative financial instruments liabilities	(1,548)	(40)	(1,603)	(1,561)	(82)	(4,834)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	332	0	0	0	0	332
Current financial investments	14,810	0	0	0	0	14,810
Cash and cash equivalents	40,500	0	0	0	0	40,500
Total assets held	55,642	0	0	0	0	55,642
At 31 December 2010						
Non-derivative financial liabilities	(88,093)	(15,822)	(35,010)	(38,356)	(58,012)	(235,293)
Derivative financial instruments liabilities	(20)	241	(1,879)	(1,377)	(1,529)	(4,564)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	1,462	0	0	0	0	1,462
Current financial investments	5,348	0	0	0	0	5,348
Cash and cash equivalents	30,251	0	0	0	0	30,251
Total assets held	37,061	0	0	0	0	37,061
At 31 December 2009						
Non-derivative financial liabilities	(72,789)	(17,910)	(24,854)	(49,536)	(52,349)	(217,438)
Derivative financial instruments liabilities	(613)	24	(766)	(1,672)	(1,064)	(4,091)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	301	0	0	0	0	301
Current financial investments	2,017	0	0	0	0	2,017
Cash and cash equivalents	24,567	0	0	0	0	24,567
Total assets held	26,885	0	0	0	0	26,885

For further information about the groups Cash and cash equivalents see note 20 *Cash and cash equivalents*.

Credit risk

Credit risk is the risk that Statoil's customers or counterparties will cause the group 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 at least annually 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 the group 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 the group's assessment of the counter-party's credit risk. Included in current and non-current derivative financial instruments are only non-exchange traded instruments.

(in NOK million)	Non-current financial receivables	Trade and other receivables	Non-current derivative financial instruments	Current derivative financial instruments
At 31 December 2011				
Investment grade, rated A or above	1,030	31,148	19,403	3,508
Other investment grade	0	35,806	13,306	2,292
Non-investment grade or not rated	575	27,709	14	132
Total financial asset	1,605	94,663	32,723	5,932
At 31 December 2010				
Investment grade, rated A or above	987	29,614	12,444	4,291
Other investment grade	565	8,132	8,119	1,081
Non-investment grade or not rated	200	30,702	0	640
Total financial asset	1,752	68,448	20,563	6,012
At 31 December 2009				
Investment grade, rated A or above	1,081	25,119	10,975	3,501
Other investment grade	543	5,417	6,669	1,060
Non-investment grade or not rated	0	22,514	0	635
Total financial asset	1,624	53,050	17,644	5,196

As of 31 December 2011, NOK 10.8 billion of cash was held as collateral to mitigate a portion of the Statoil's credit exposure. The collateral is cash received as 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 *Non-current derivative financial instruments* and *Current derivative financial instruments* presented in the above table.

8.1.8 Remuneration

(in NOK million, except average number of man-labour years)	For the year ended 31 December		
	2011	2010	2009
Salaries	21,131	19,831	18,221
Pension costs	3,757	4,138	3,538
Payroll tax	3,257	2,972	3,023
Other compensations and social costs	2,533	2,158	2,177
Total payroll costs	30,678	29,099	26,959
Average number of man-labour years	29,378	28,396	28,107

Total payroll expenses are accumulated in cost-pools and partly charged to partners of Statoil-operated licences on an hours incurred basis.

The calculation of pension costs and pension assets/liabilities is described in note 23 *Pensions and other non-current employee benefits*.

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, amount vested for bonus shares granted and related social security tax was NOK 451, NOK 427 and NOK 370 million related to the 2011, 2010 and 2009 programs, respectively. For the 2012 program (granted in 2011) the estimated compensation expense is NOK 512 million. At 31 December 2011 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 1,024 million.

8.1.9 Other expenses

Auditor's remuneration

(in NOK million, excluding VAT)	Audit fee	Audit related fee	Other service fee	Total
Year ended 31 December 2011				
Ernst & Young - Norway	36.6	5.0	3.3	44.9
Ernst & Young - outside Norway	25.8	1.8	0.0	27.6
Total	62.4	6.8	3.3	72.5
Year ended 31 December 2010				
Ernst & Young - Norway	35.2	12.2	0.1	47.5
Ernst & Young - outside Norway	29.3	2.0	0.1	31.4
Total	64.5	14.2	0.2	78.9
Year ended 31 December 2009				
Ernst & Young - Norway	34.2	5.3	3.7	43.2
Ernst & Young - outside Norway	27.1	1.5	0.9	29.5
Total	61.3	6.8	4.6	72.7

In addition to the figures in the table above, the audit fees and audit related fees to Ernst & Young related to Statoil-operated licences amount to NOK 8.8, NOK 8.8 and NOK 8.9 million for 2011, 2010 and 2009, respectively.

Research and development expenditures (R&D)

Research and development expenditures were NOK 2,201, NOK 2,045 and NOK 2,073 million in 2011, 2010 and 2009, 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.

8.1.10 Financial items

(in NOK million)	2011	For the year ended 31 December 2010	2009
Foreign exchange gains (losses) derivative financial instruments	1,601	(1,736)	9,722
Foreign exchange gains (losses) taxes payable	24	(473)	(1,930)
Other foreign exchange gains (losses)	(1,260)	383	(5,803)
Net foreign exchange gains (losses)	365	(1,826)	1,989
Dividends received	137	132	66
Gains (losses) financial investments	(1,297)	660	875
Interest income financial investments	535	325	354
Interest income non-current financial receivables	87	86	106
Interest income current financial assets and other financial income	1,845	1,910	2,307
Interest income and other financial items	1,307	3,113	3,708
Interest expense bonds and bank loans and net interest on related derivatives	(2,166)	(2,115)	(2,111)
Interest expense finance lease liabilities	(587)	(244)	(275)
Capitalised borrowing costs	869	995	1,351
Accretion expense asset retirement obligation	(2,810)	(2,508)	(2,432)
Gains (losses) derivative financial instruments	6,940	2,611	(6,593)
Interest expense current financial liabilities and other finance expense	(1,861)	(461)	(2,396)
Interest and other finance expenses	385	(1,722)	(12,456)
Net financial items	2,057	(435)	(6,759)

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk management. Weakening of USD versus NOK during the first three quarters of the year ended 31 December 2011 resulted in fair value gains on these positions which are recognised in the Consolidated statement of income. Correspondingly, strengthening of USD versus NOK for the year ended 31 December 2010 resulted in fair value loss and weakening of USD versus NOK for the year ended 31 December 2009 resulted in fair value gains.

Gains (losses) financial investments shows a loss in 2011 compared to 2010 and 2009. This is due to loss on commercial papers and equity instruments in 2011.

Gains (losses) derivative financial instruments include fair value changes of interest rate derivatives which are used to manage the interest rate risk of the loan portfolio. Decreasing USD interest rates for the year ended 31 December 2011 resulted in fair value gains on these positions. Correspondingly, decreasing USD interest rates for the year ended 31 December 2010 resulted in fair value gains and increasing USD interest rates for the year ended 31 December 2009 resulted in fair value losses.

Capitalised borrowing costs were reduced in 2011 and 2010 compared to 2009 due to completion of development projects and more fields going into production in 2010.

Included in Interest expense current financial liabilities and other finance expense for the year ended 31 December 2011 is interest of NOK 0.5 billion related to the Heidrun redetermination and an impairment loss of NOK 0.5 billion related to the Pernis refinery investment. In the year ended 31 December 2009, impairment loss of NOK 1.4 billion related to the Pernis refinery investment is included.

8.1.11 Income taxes

Significant components of income tax expense were as follows

(in NOK million)	For the year ended 31 December		
	2011	2010	2009
Norway offshore	118,244	90,219	80,944
Norway onshore	1,744	167	4,027
Other countries upstream*	11,284	6,014	5,169
Other countries downstream*	402	393	770
Current income tax expense	131,674	96,793	90,910
Norway offshore	6,459	1,549	9,358
Norway onshore	1,261	(2,877)	242
Other countries upstream*	(3,022)	2,322	(3,094)
Other countries downstream*	(974)	1,392	(221)
Deferred tax expense	3,724	2,386	6,285
Income tax expense	135,398	99,179	97,195

* Includes Norwegian taxes on income in other countries.

Reconciliation of nominal statutory tax rate to effective tax rate

(in NOK million)	For the year ended 31 December		
	2011	2010	2009
Norway offshore	169,757	122,935	122,074
Norway onshore	11,213	368	(10,700)
Other countries upstream	32,971	12,133	2,753
Other countries downstream	(100)	1,390	783
Total income before tax	213,841	136,826	114,910
Calculated Norwegian income taxes at Norwegian statutory rate	50,672	34,525	31,185
Calculated Norwegian Petroleum surtax at statutory rate (special tax rate 50%)*	84,878	61,468	61,037
Calculated other countries upstream income taxes at domestic statutory rates	13,314	7,573	2,059
Calculated other countries downstream income taxes at domestic statutory rates	65	1,017	1,869
Uplift*	(5,075)	(4,957)	(5,052)
Tax effect of permanent differences	(5,700)	719	5,343
Recognition of previously unrecognised deferred tax assets**	(3,143)	0	0
Prior period adjustments	(49)	(736)	156
Other items	436	(430)	598
Income tax expense	135,398	99,179	97,195
Effective tax rate	63.32%	72.49%	84.58%

* When computing the special petroleum tax 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 2011 and 2010 unrecognised uplift credits amounted to NOK 15.1 and 14.5 billion, respectively.

** As part of the purchase price allocation (PPA) for the aquisition of Brigham Exploration Company (see note 5 *Business development*) an amount of NOK 8.7 billion of deferred tax liabilities was recognised at 1 December 2011. 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 part of the United States operations were recognised in 2011.

Deferred tax assets and liabilities comprise

(in NOK million)	Inventory	Other current items	Tax losses carried forwards	Property, plant and equipment	Exploration expenditure	ARO	Pensions	Other non-current items	Total
Deferred tax at 31 December 2011									
Deferred tax assets	437	2,596	10,977	9,163	0	55,376	6,663	7,404	92,616
Deferred tax liabilities	0	(1,796)	0	(115,502)	(28,453)	0	0	(23,681)	(169,432)
Net asset (liability) at 31 December 2011	437	800	10,977	(106,339)	(28,453)	55,376	6,663	(16,277)	(76,816)
Deferred tax at 31 December 2010									
Deferred tax assets	1,060	3,302	2,812	6,705	0	43,378	7,490	3,389	68,136
Deferred tax liabilities	0	(1,275)*	0	(103,493)	(19,128)	0	0	(20,427)*	(144,323)
Net asset (liability) at 31 December 2010	1,060	2,027	2,812	(96,788)	(19,128)	43,378	7,490	(17,038)	(76,187)
Deferred tax at 31 December 2009									
Deferred tax assets	907	2,123	3,098	10,162	0	34,072	8,148	2,668	61,178
Deferred tax liabilities	0	(815)*	0	(96,799)	(20,091)	0	0	(17,848)*	(135,553)
Net asset (liability) at 31 December 2009	907	1,308	3,098	(86,637)	(20,091)	34,072	8,148	(15,180)	(74,375)

Analysis of movements during the year	2011	2010	2009
Net deferred tax liability at 1 January	76,187	74,375	66,842
Charged (credited) to the Consolidated statement of income	3,724	2,386	6,285
Other comprehensive income pensions	(2,028)	(16)	742
Charged (credited) to Equity	0	0	155
Translation differences and other	(1,067)	(558)	351
Net deferred tax liability at 31 December	76,816	76,187	74,375

* Amount has been reclassified in order to be comparable to the 2011 presentation.

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.

Deferred tax assets

As at 31 December 2011 Statoil had recognised net deferred tax assets of NOK 5.7 billion, primarily in Norway, as it is considered probable that taxable profit will be available to utilise these deferred tax assets.

Unrecognised deferred tax assets

(in NOK million)	2011	At 31 December 2010	2009
Deductible temporary differences	3,661	6,345*	6,214*
Tax losses carry forward	9,044	9,063	4,461

* Amount has been reclassified in order to be comparable to the 2011 presentation.

Approximately 50% of the tax losses carry-forwards that have not been recognised, expire in the period 2019-2026. The majority of the remaining part may be carried forward indefinitely. 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 evidence, as required by prevailing accounting standards, is currently not sufficient to support that future taxable profits will be available to secure utilisation of the benefits.

8.1.12 Earnings per share

Basic earnings per share

The calculation of basic and diluted earnings per share is based on the net income attributable to ordinary shareholders of the parent company and a weighted average number of ordinary shares outstanding during the years ended 31 December 2011, 2010 and 2009 respectively, as follows:

	2011	2010	2009
Net income attributable to equity holders of the parent company (in NOK million)	78,787	38,082	18,313
Weighted average number of ordinary shares (in thousands of shares)	3,182,113	3,182,575	3,183,874
Effect of treasury shares held	7,931	7,114	6,028
Weighted average number of ordinary shares, diluted	3,190,044	3,189,689	3,189,902
Earnings per share for income attributable to equity holders of the company:			
Basic (NOK)	24.76	11.97	5.75
Diluted (NOK)	24.70	11.94	5.74

Statoil has no share based payments with significant dilutive effects.

8.1.13 Property, plant and equipment

(in NOK million)	Machinery, equipment and transportation equipment	Production plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2010	17,705	678,216	55,476	16,533	4,434	76,118	848,482
Transferred from assets classified as held for sale**	0	0	0	0	0	32,515	32,515
Additions and transfers	1,930	98,413	1,267	812	0	1,953	104,375
Addition from business combination***	68	6,266	0	4	0	1,176	7,514
Disposals assets at cost	(1,246)	(38,653)	(3,400)	(135)	0	(13,537)	(56,971)
Effect of movements in foreign exchange - assets	209	7,131	294	(305)	102	(544)	6,887
Cost at 31 December 2011	18,666	751,373	53,637	16,909	4,536	97,681	942,802
Accumulated depreciation and impairment losses at 31 December 2010	(12,959)	(437,610)	(36,746)	(6,648)	(1,305)	(1,636)	(496,904)
Additions and transfers	0	0	0	0	0	(2,155)	(2,155)
Depreciation and net impairment losses for the year	(1,747)	(45,427)	(5,741)	(786)	(228)	1,817	(52,112)
Accumulated depreciation and impairment disposed assets	944	16,435	1,935	127	0	38	19,479
Effect of movements in foreign exchange - depreciation and impairment losses	(182)	(3,431)	(156)	113	(45)	176	(3,525)
Accumulated depreciation and impairment losses at 31 December 2011	(13,944)	(470,033)	(40,708)	(7,194)	(1,578)	(1,760)	(535,217)
Carrying amount at 31 December 2011	4,722	281,340	12,929	9,715	2,958	95,921	407,585
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

(in NOK million)	Machinery, equipment and transportation equipment	Production plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2009	18,549	618,487	44,098	15,735	4,079	90,250	791,198
Additions and transfers	(267)	61,026	11,642	1,086	195	18,780	92,462
Disposals assets at cost	(721)	(2,894)	(418)	(291)	(11)	(1,426)	(5,761)
Assets classified as held for sale	0	0	0	0	0	(32,515)	(32,515)
Effect of movements in foreign exchange - assets	144	1,597	154	3	171	1,029	3,098
Cost at 31 December 2010	17,705	678,216	55,476	16,533	4,434	76,118	848,482
Accumulated depreciation and impairment losses at 31 December 2009	(12,205)	(397,591)	(31,794)	(6,003)	(1,018)	(67)	(448,678)
Depreciation and net impairment for the year	(1,252)	(41,570)	(5,074)	(671)	(286)	(1,655)	(50,508)
Accumulated depreciation and impairment disposed assets	531	2,681	266	144	11	0	3,633
Effect of movements in foreign exchange - depreciation and impairment losses	(33)	(1,130)	(144)	(118)	(12)	86	(1,351)
Accumulated depreciation and impairment losses at 31 December 2010	(12,959)	(437,610)	(36,746)	(6,648)	(1,305)	(1,636)	(496,904)
Carrying amount at 31 December 2010	4,746	240,606	18,730	9,885	3,129	74,482	351,578
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

(in NOK million)	Machinery, equipment and transportation equipment	Production plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 1 January 2009	18,231	582,066	42,224	16,528	5,604	77,883	742,536
Additions and transfers	4,379	58,269	2,532	1,431	(788)	21,097	86,920
Disposals assets at cost	(1,411)	(514)	(223)	(348)	0	0	(2,496)
Effect of movements in foreign exchange - assets	(2,650)	(21,334)	(435)	(1,876)	(737)	(8,730)	(35,762)
Cost at 31 December 2009	18,549	618,487	44,098	15,735	4,079	90,250	791,198
Accumulated depreciation and impairment losses at 1 January 2009	(10,856)	(365,575)	(27,140)	(6,311)	(869)	(1,521)	(412,272)
Depreciation and net impairment losses for the year	(3,468)	(43,570)	(5,001)	(617)	(333)	319	(52,670)
Accumulated depreciation and impairment disposed assets	867	513	139	214	0	0	1,733
Effect of movements in foreign exchange - depreciation and impairment losses	1,252	11,041	208	711	184	1,135	14,531
Accumulated depreciation and impairment losses at 31 December 2009	(12,205)	(397,591)	(31,794)	(6,003)	(1,018)	(67)	(448,678)
Carrying amount at 31 December 2009	6,344	220,896	12,304	9,732	3,061	90,183	342,520
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

* Depreciation according to Unit of production method, see note 2 *Significant accounting policies*.

** Reflects a reversal of previous period's assets classified as held for sale for which the portion sold during the period is included as Disposals.

*** For information on assets from business combination, see note 5 *Business development*.

In 2011, 2010 and 2009 capitalised borrowing cost amounted to NOK 0.9 billion, NOK 1.0 billion and NOK 1.4 billion, respectively.

The carrying amount of transfer of assets to *Property, plant and equipment* from *Intangible assets* in 2011, 2010 and 2009 amounted to NOK 3.7 billion, NOK 11.0 billion and NOK 4.9 billion, respectively.

(in NOK million)	2011	For the year ended 31 December 2010	2009
Impairment losses	(4,718)	(4,820)	(8,176)
Reversal of impairment losses	2,692	280	1,743
Net impairment losses	(2,026)	(4,540)	(6,433)

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 is 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 in the DPI segment of NOK 2.6 billion related to assets in the Gulf of Mexico. The basis for the impairment losses are 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 were 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 were reduced value in use estimate mainly driven by project delays, changes in certain cost estimates and market conditions.

In 2009 Statoil recognised impairment losses in the MPR segment related to machinery equipment and refinery assets of NOK 2.2 billion and NOK 3.2 billion, respectively.

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. When preparing a value in use calculation the estimated future cash flows are adjusted for risks specific to the asset and discounted using a real post-tax discount rate adjusted for asset specific differences. 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. 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.

8.1.14 Intangible assets

(in NOK million)	Exploration expenditure	Goodwill	Other	Total
Cost at 31 December 2010	38,351	4,353	2,395	45,099
Transferred from assets classified as held for sale *	12,375	0	0	12,375
Additions	14,206	0	295	14,501
Addition through business combination**	24,056	6,867	0	30,923
Disposals intangible assets at cost	(5,524)	0	(5)	(5,529)
Transfers of intangible assets	(3,664)	0	(9)	(3,673)
Expensed exploration expenditures previously capitalised	(1,531)	0	0	(1,531)
Effect of movements in foreign exchange	1,348	170	90	1,608
Cost at 31 December 2011	79,617	11,390	2,767	93,774
Accumulated amortisation and impairment losses at 31 December 2010		(389)	(1,539)	(1,928)
Depreciation, impairments and amortisation for the year		0	(114)	(114)
Reversal of impairment		0	875	875
Disposals amortisation and impairment losses		0	0	0
Effect of movements in foreign exchange - amortisation and imp. losses		0	67	67
Accumulated amortisation and impairment losses at 31 December 2011		(389)	(711)	(1,100)
Carrying amount at 31 December 2011	79,617	11,001	2,056	92,674

(in NOK million)	Exploration expenditure	Goodwill	Other	Total
Cost at 31 Desember 2009	49,451	4,392	2,257	56,100
Additions	14,702	2	251	14,955
Disposals intangible assets at cost	(795)	(20)	(202)	(1,017)
Transfers of intangible assets	(10,964)	(24)	8	(10,980)
Assets classified as held for sale	(12,375)	0	0	(12,375)
Expensed exploration expenditures previously capitalised	(2,911)	0	0	(2,911)
Effect of movements in foreign exchange	1,243	2	81	1,326
Cost at 31 December 2010	38,351	4,353	2,395	45,099
Accumulated amortisation and impairment losses at 31 December 2009		(360)	(1,396)	(1,756)
Depreciation, impairments and amortisation for the year		(36)	(150)	(186)
Disposals amortisation and impairment losses		0	10	10
Effect of movements in foreign exchange - amortisation and imp. losses		7	(3)	4
Accumulated amortisation and impairment losses at 31 December 2010		(389)	(1,539)	(1,928)
Carrying amount at 31 December 2010	38,351	3,964	856	43,171

(in NOK million)	Exploration expenditure	Goodwill	Other	Total
Cost at 1 January 2009	61,488	3,595	1,936	67,019
Additions	7,907	1,042	75	9,024
Addition through business combination	0	0	497	497
Disposals intangible assets at cost	(774)	0	(49)	(823)
Transfers of intangible assets	(4,888)	0	10	(4,878)
Expensed exploration expenditures previously capitalised	(6,998)	0	0	(6,998)
Effect of movements in foreign exchange	(7,284)	(245)	(212)	(7,741)
Cost at 31 December 2009	49,451	4,392	2,257	56,100
Accumulated amortisation and impairment losses at 1 January 2009		(583)	(400)	(983)
Depreciation, impairments and amortisation for the year		0	(1,161)	(1,161)
Disposals amortisation and impairment losses		0	15	15
Effect of movements in foreign exchange - amortisation and imp. losses		223	150	373
Accumulated amortisation and impairment losses at 31 December 2009		(360)	(1,396)	(1,756)
Carrying amount at 31 December 2009	49,451	4,032	861	54,344

* Reflects a reversal of previous periods assets classified as held for sale for which the portion sold during the period is included as Disposals.

** For information on addition through business combination see note 5 *Business development*.

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 table below shows the Net impairment losses related to intangible assets which have been recognised in the reporting periods for each line item under which it has been reported. The subsequent table shows the components of the exploration expenses.

(in NOK million)	2011	For the year ended 31 December 2010	2009
Depreciation, amortisation and net impairment losses	0	31	1,003
Exploration expenses	1,573	1,935	5,418
Impairment losses	1,573	1,966	6,421
Depreciation, amortisation and net impairment losses	(875)	0	0
Exploration expenses	(1,872)	(1,636)	0
Reversal of impairment losses	(2,747)	(1,636)	0
Net impairment losses	(1,174)	330	6,421

Exploration expenses

(in NOK million)	2011	For the year ended 31 December 2010	2009
Exploration expenditure	18,754	16,803	16,891
Expensed exploration expenditures previously capitalised	1,531	2,911	6,998
Capitalised exploration	(6,446)	(3,941)	(7,203)
Exploration expenses	13,839	15,773	16,686

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 and relate mainly to exploration assets in the Gulf of Mexico, recognised in the Development and Production International segment. See note 13 *Property, plant and equipment* for further information on the basis for impairment assessments.

8.1.15 Investments in associated companies

(in NOK million)	2011	2010	2009
Investments in associated companies at 31 December	9,217	8,997	9,424
Net income from associated companies	1,264	1,168	1,457

The most significant associated companies included in the table above are Petrocedeño S.A. (ownership share 9.68%), BTC Pipeline company (ownership share 8.71%) and South Caucasus Pipeline Hold Co (ownership share 25.5%). Statoil has assessed that through contractual agreements the group has significant influence over the BTC Pipeline company and Petrocedeño S.A., and consequently the ownership interests in these companies are accounted for under the equity method.

For information on jointly controlled entities for which the accounting policy was changed from the equity method to proportionate consolidation, see note 3 *Accounting policy change for jointly controlled entities*.

8.1.16 Non-current financial assets and prepayments

(in NOK million)	2011	At 31 December 2010	2009
Bonds	7,987	7,213	6,726
Listed equity securities	4,539	5,102	4,318
Non-listed equity securities	2,859	3,042	2,223
Financial investments	15,385	15,357	13,267

Bonds and Listed equity securities relate to investment portfolios held by Statoil's captive insurance company which are 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. The total decrease of NOK 0.2 billion in 2011 is mainly caused by impairment of NOK 0.5 billion related to the Pernis refinery investment and capital payments of NOK 0.4 billion related to the Shtokman investment and Marine Well Containment Company.

During 2011 a loss of NOK 0.2 billion was recognised in Other comprehensive income. For 2010 a gain of NOK 0.2 billion was recognised in Other comprehensive income.

(in NOK million)	2011	At 31 December 2010	2009
Financial receivables interest bearing	1,605	1,752	1,624
Prepayments and other non-interest bearing receivables	1,738	2,193	2,583
Prepayments and financial receivables	3,343	3,945	4,207

Included in Financial receivables interest bearing are project financing of the equity accounted investment BTC and financing of the associated company European CO2 Technology Centre.

The Financial receivables interest bearing are classified in the loan and receivables category, the Prepayments and other non-interest bearing receivables are classified as non-financial assets.

The carrying amount of non-current financial receivables and current financial receivables (classified as trade and other receivables, see note 18 *Trade and other receivables*), including accrued interest approximate fair value.

8.1.17 Inventories

Inventories are valued at the lower of cost and net realisable value. Inventories of crude oil, refined products and non-petroleum products are determined under the first-in, first-out (FIFO) method.

The carrying amount of inventory at the beginning of the year has in all material respects been recognised as an expense through *Purchases [net of inventory variation]* during the year.

(in NOK million)	2011	At 31 December 2010	2009
Crude oil	16,325	14,856	11,371
Petroleum products	8,884	7,210	7,778
Other	2,561	1,561	1,047
Inventories	27,770	23,627	20,196

8.1.18 Trade and other receivables

(in NOK million)	2011	At 31 December 2010	2009
Financial trade and other receivables:			
Trade receivables	86,445	63,184	48,887
Current financial receivables	1,604	570	0
Receivables joint ventures	5,871	4,214	3,580
Receivables associated companies and other related parties	743	480	583
Total financial trade and other receivables	94,663	68,448	53,050
Non-financial trade and other receivables	8,598	6,362	5,942
Trade and other receivables	103,261	74,810	58,992

For more information about the credit quality of Statoil's financial assets see note 7 *Financial risk management*. For currency sensitivities see note 31 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

For further information on financial receivables, see note 16 *Non-current financial assets and prepayments*.

8.1.19 Current financial investments

(in NOK million)	2011	At 31 December 2010	2009
Bonds	482	1,183	675
Commercial papers	12,888	8,767	4,681
Money market funds	6,508	1,559	1,584
Other	0	0	82
Financial investments	19,878	11,509	7,022

Current financial investments at 31 December 2011 are classified as held for trading, except for NOK 5.1 billion related to investment portfolios held by the Statoil's captive insurance company which are accounted for using the fair value option. The corresponding balances at 31 December 2010 and 2009 were NOK 6.2 billion and NOK 5.0 billion accounted for using the fair value option.

Current financial investments are measured at fair value with gains and losses recognised in the Consolidated statement of income.

8.1.20 Cash and cash equivalents

(in NOK million)	2011	At 31 December 2010	2009
Cash at bank available	10,374	11,126	10,435
Time deposits	24,120	13,004	13,073
Restricted cash, including collateral deposits	6,102	6,391	1,778
Cash and cash equivalents	40,596	30,521	25,286

Restricted cash at 31 December 2011 include collateral deposits of NOK 1.8 billion related to trading activities. Correspondingly collateral deposits at 31 December 2010 were NOK 3.8 billion and collateral deposits at 31 December 2009 were NOK 1.8 billion. Collateral deposits are related to certain

requirements set out by exchanges where the group is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

Restricted cash at 31 December 2011 include NOK 4.3 billion deposited with Statoil's US dollar denominated bank account in Nigeria. Correspondingly restricted cash in Nigeria at 31 December 2010 was NOK 2.6 billion. There was no restricted cash in Nigeria at 31 December 2009. There are certain restrictions on the use of cash from Statoil's Nigerian operations following an injunction against Statoil by the Nigerian courts related to an ongoing litigation claim. Both the injunction and the disputed claim have been appealed. Of the total restricted cash at 31 December 2011, NOK 3.9 billion is no longer to be reported as restricted cash from March 2012.

The bank overdraft facilities are included in note 26 *Bonds, bank loans, commercial papers and collateral liabilities*, which are included in the cash and cash equivalent in the Consolidated statement of cash flows.

8.1.21 Transactions impacting shareholders equity

Statoil 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 ordinary shares are entitled to receive dividends as declared from time to time and are entitled to one vote per share at general meetings of the company.

Dividends declared and paid per share were NOK 6.25 in 2011 for Statoil ASA and NOK 6.00 and NOK 7.25 in 2010 and 2009, respectively. A dividend for 2011 of NOK 6.5 per share, amounting to a total dividend of NOK 20.7 billion, will be proposed at the annual general meeting in May 2012. The proposed dividend is not recognised as a liability in the Consolidated financial statements.

Retained earnings available for distribution of dividends at 31 December 2011 are limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 153,198 million (before provisions for proposed dividend for the year ended 31 December 2011 of NOK 20,705 million). This differs from *Retained earnings* in the Consolidated balance sheet of NOK 218,518 million. In accordance with Norwegian legal requirements dividends are not allowed to reduce the shareholders' equity of the parent company below 10% of total assets.

The annual general meeting in 2011 authorised the board of directors of Statoil ASA to acquire Statoil shares in the market on behalf of the company. The authorisation may be used to acquire Statoil shares with an overall nominal value of up to NOK 20 million. Shares acquired pursuant to this authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan, as approved by the board of directors. The minimum and maximum amount that may be paid per share will be NOK 50 and 500, respectively. The authorisation is valid until the next ordinary general meeting. This authorisation replaces the previous authorisation to enquire own shares for implementation of the share saving plan for employee granted by the annual general meeting in 2010.

The annual general meeting in 2011 also authorised the board of directors of Statoil ASA to acquire Statoil shares in the market for subsequent annulment on behalf of the company with a nominal value of up to NOK 187.5 million. The minimum and maximum amount that can be paid per share is NOK 50 and 500, respectively. Within these limits, the board of directors shall decide at what price and at what time such acquisition shall take place, if any. Own shares acquired pursuant to this authorisation may only be used for annulment through a reduction of the company's share capital, pursuant to the Public Limited Companies Act section 12-1. The authorisation is valid until the next ordinary general meeting.

During 2011 a total of 2,931,346 treasury shares were purchased for NOK 408 million. At 31 December 2011 Statoil had 7,931,347 treasury shares all of which are related to the group's share saving plan.

8.1.22 Bonds, bank loans and finance lease liabilities

	Weighted average interest rates in %			Carrying amount in NOK million at 31 December			Fair value in NOK million at 31 December		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Financial liabilities measured at amortised cost									
Unsecured bonds									
US dollar (USD)	4.92	5.41	5.85	65,510	52,586	40,610	74,778	57,736	43,632
Euro (EUR)	4.99	5.01	5.13	19,454	23,504	27,515	23,128	26,698	30,397
Japanese yen (JPY)	1.66	1.66	1.66	387	360	312	392	368	322
Great Britain									
Pound (GBP)	6.71	6.71	6.71	9,522	9,302	9,556	13,232	11,456	11,391
Total				94,873	85,752	77,993	111,530	96,258	85,742
Unsecured loans									
US dollar (USD)	0.74	0.74	0.71	5,912	5,779	5,697	5,957	5,747	5,639
Norwegian									
kroner (NOK)	4.04	3.88	-	3,994	3,974	-	3,994	3,974	-
Japanese yen (JPY)	1.65	1.65	1.65	619	576	501	629	589	516
Secured bank loans									
US dollar (USD)	3.48	3.70	3.74	523	695	864	523	695	894
Other currencies	3.80	3.31	4.63	122	142	135	122	142	135
Finance lease liabilities				11,950	7,159	13,747	11,950	7,159	13,747
Other liabilities				786	347	293	786	347	293
Total				23,906	18,672	21,237	23,961	18,653	21,224
Total liabilities outstanding				118,779	104,424	99,230	135,491	114,911	106,966
Less current portion				7,168	4,627	3,268	7,168	4,627	3,268
Bonds, bank loans and finance lease liabilities				111,611	99,797	95,962	128,323	110,284	103,698

On 23 November 2011 Statoil ASA issued new bonds 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. The 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.

More information regarding finance lease liabilities is provided in note 27 *Leases*.

The table does not include the effects of agreements entered into to swap the various currencies into USD. For further information see note 30 *Financial instruments by category*.

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 subject to fair value measurement. The credit premium used is based on indicative pricing from external financial institutions.

Details of largest unsecured bonds:

Bond agreement	Fixed interest rate	Issued (year)	Maturity (year)	Carrying amount in NOK million at		
				2011	31 December 2010	2009
USD 1500 million	5.250 %	2009	2019	8,947	8,738	8,613
USD 1250 million	3.125 %	2010	2017	7,454	7,278	-
USD 900 million	2.900 %	2009	2014	5,378	5,251	5,174
USD 750 million	3.150 %	2011	2022	4,467	-	-
USD 750 million	5.100 %	2010	2040	4,443	4,340	-
USD 650 million	1.800 %	2011	2016	3,876	-	-
USD 500 million	5.125 %	2004	2014	2,996	2,927	2,887
USD 500 million	3.875 %	2009	2014	2,986	2,914	2,870
USD 500 million	6.500 %	1998	2028	2,969	2,900	2,859
USD 481 million	7.250 %	2000	2027	2,880	2,814	2,776
USD 350 million	4.250 %	2011	2041	2,079	-	-
EUR 1300 million	4.375 %	2009	2015	10,064	10,135	10,782
EUR 1200 million	5.625 %	2009	2021	9,235	9,297	9,887
GBP 800 million	6.875 %	2009	2031	7,397	7,224	7,421
GBP 225 million	6.125 %	1998	2028	2,098	2,040	2,096

Currency swaps are used for risk management purposes. Unsecured bonds are either denominated in US dollar, amounting to NOK 65.5 billion or the bonds are swapped into US dollar, amounting to NOK 29.4 billion. Interest rate swaps are used to manage the interest rate risk on the unsecured bond contracts with fixed interest rates. As a result the majority of the portfolio is swapped from fixed to floating interest rate.

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 2.1 billion, in addition, security includes the group's pro-rata share of income from certain applicable projects.

Statoil has 31 unsecured bond agreements outstanding which contain provisions allowing the group 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 93.1 billion at the 31 December 2011 closing rate.

Statoil ASA has an undrawn revolving credit facility for USD 3.0 billion supported by 20 core banks. For more information see note 7 *Financial risk management*.

Maturity profile bonds, bank loans and finance lease liabilities

(in NOK million)	2011	At 31 December 2010	2009
Year 2 and 3	21,337	12,555	11,757
Year 4 and 5	21,814	23,205	11,496
After 5 years	68,460	64,037	72,709
Total repayment	111,611	99,797	95,962

Maturity profile for undiscounted cash flows is shown in note 7 *Financial risk management*.

	2011	At 31 December 2010	2009
Bonds, bank loans and finance lease liabilities (in NOK million)	111,611	99,797	95,962
Weighted average maturity (year)	9	9	9
Weighted average annual interest rate (%)	4.84	5.01	4.77

8.1.23 Pensions and other non-current employee benefits

The Norwegian companies in the group are obligated to follow 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 the company's Norwegian subsidiaries. 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 Insurance Scheme ("Folketrygden") provides pension payments (social security) to all retired Norwegian citizens. Such payments are calculated by references to a base amount annually approved by the Norwegian parliament ("Grunnbeløpet" or "G"). Statoil's plan benefits are generally based on 30 years of service and 66% of the final salary level, when first including the public funding to be provided from the Norwegian Insurance Scheme ("Folketrygden").

The cost of pension benefit plans is expensed over the period that the employee renders services and becomes eligible to receive benefits. The obligations related to defined benefit plans are calculated by external actuaries.

Some Statoil companies have defined contribution plans. The period's contributions are recognised in the Statement of income as pension cost for the period.

New legislation in Norway affecting the early retirement pension plans in the National Insurance Scheme became effective 1 January 2011. The changes include the introduction of flexible withdrawal of retirement pension from age 62 and earnings of pension benefits to vesting age, previously known as pension age.

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 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 to employees for their full lifetime.

The employers have an obligation to pay the main share of the benefits under the AFP scheme, while the remaining obligation is the Norwegian state's responsibility. In the current early retirement system Statoil offers a supplementary company pension for employees. Statoil therefore has a combined early retirement commitment to the employees irrespectively of the public level of funding. The combined early retirement plan is accounted for as one defined benefit plan, and is included in the liabilities related to the defined benefit plans. Consequently the replacement of the old AFP with a new AFP in 2010 was not regarded as a termination of the plan.

The obligations related to the defined benefit plans were measured at 31 December for 2011 and 2010. 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 2011 the discount rate for the defined benefit plans in Norway was estimated to be 3.25% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 20.6 year yield curve which matches the duration of Statoil's payment portfolio for earned benefits.

Actuarial gains and losses are recorded directly in *Other comprehensive income* in the period in which they occur. Actuarial gains and losses related to the provision for termination benefits are recognised in the Statement of income in the period in which they occur.

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 not disclosed separately.

Net pension cost

(in NOK million)	For the year ended 31 December		
	2011	2010	2009
Current service cost	3,588	3,491	2,747
Interest cost	2,702	2,725	2,550
Expected return on plan assets	(2,869)	(2,661)	(1,896)
Actuarial (gain)/loss related to termination benefits	56	185	(172)
Past service cost	0	3	0
Effect of limit in IAS 19.58(b)	0	4	0
Losses (gains) from curtailment or settlement	(23)	0	0
Defined benefit plans	3,454	3,747	3,229
Defined contribution plans	216	230	240
Multi-employer plans	87	161	69
Total net pension cost	3,757	4,138	3,538

Pension cost includes associated social security tax.

Pension cost is partly charged to partners of Statoil operated licences.

For information regarding pension benefits for key management personnel, reference is made to note 29 *Related parties*.

Change in projected benefit obligation (PBO)

(in NOK million)	2011	2010
Projected benefit obligation at 1 January	67,821	61,427
Current service cost	3,588	3,491
Interest cost	2,702	2,725
Actuarial loss (gain)	2,865	1,955
Benefits paid	(1,727)	(1,821)
Acquisition and sale	(56)	0
Foreign currency translation	(149)	44
Projected benefit obligation at 31 December	75,044	67,821

Change in pension plan assets

(in NOK million)	2011	2010
Fair value of plan assets at 1 January	50,976	42,979
Expected return on plan assets	2,869	2,661
Actuarial gain (loss)	(4,540)	1,678
Company contributions (including social security tax)	3,332	4,122
Benefits paid	(508)	(505)
Acquisition and sale	(32)	0
Foreign currency translation	(149)	41
Fair value of plan assets at 31 December	51,948	50,976

The tables above for Change in projected benefit obligation (PBO) and Change in pension plan assets do not include currency effects for Statoil ASA. For more information see the table Actuarial gains and losses recognised directly in Other comprehensive income below.

Changes in net pension liability

(in NOK million)	2011	2010
Balance sheet provision at 1 January	(16,845)	(18,448)
Net periodic pension costs defined benefit plans	(3,454)	(3,747)
Net actuarial (loss) gain recognised in Other comprehensive income*	(7,364)	(33)
Less employer contributions	3,332	4,122
Less benefit paid during year	1,218	1,316
Foreign currency translation and other changes	17	(55)
Balance sheet provision at 31 December	(23,096)	(16,845)

Net benefit liability at 31 December

(in NOK million)	2011	2010	2009	2008	2007
Net benefit liability at 31 December	(23,096)	(16,845)	(18,448)	(25,508)	(17,633)
Represented by:					
Asset recognised as Non-current pension asset	3,888	5,265	2,694	30	1,622
Liability recognised as Non-current pension liability	(26,984)	(22,110)	(21,142)	(25,538)	(19,092)
Liability recognised as current liability	0	0	0	0	(163)

Projected benefit obligation specified by funded and unfunded plans

(in NOK million)	2011	2010	2009
Funded pension plans	(48,078)	(45,753)	(40,212)
Unfunded pension plans	(26,966)	(22,068)	(21,215)
Projected benefit obligation at 31 December	(75,044)	(67,821)	(61,427)

Actuarial gains and losses recognised directly in Other comprehensive income

(in NOK million)	2011	2010	2009
Unrecognised actuarial losses (gains) at 1 January	0	0	0
Actuarial losses (gains) on plan assets occurred during the year	4,540	(1,678)	(2,819)
Actuarial losses (gains) on benefit obligation occurred during the year	2,865	1,955	(1,308)
Actuarial losses (gains) related to currency effects on net obligation	255	(245)	3,867
Foreign exchange translation	(240)	186	(3,103)
Recognised in the income statement during the year	(56)	(185)	172
Recognised in Other comprehensive income during the year*	(7,364)	(33)	3,191
Unrecognised actuarial losses (gains) at 31 December	0	0	0

* The net actuarial (loss) gain for 2011 is mainly related to the changes in estimated early retirement obligation reflecting the Norwegian Pension reform.

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. The line Foreign exchange translation relates to the translation of the net pension obligation from the functional currency USD to Statoil's presentation currency NOK.

Actual return on plan assets

(in NOK million)	For the year ended 31 December		
	2011	2010	2009
Actual return on plan assets	(1,674)	4,339	4,715

History of experience gains and losses

(in NOK million)	For the year ended 31 December		
	2011	2010	2009
Difference between the expected and actual return on plan assets			
a) Amount	4.540	(1,678)	(2,819)
b) Percentage of plan assets	8.74%	(3.29%)	(6.56%)
Experience (gain)/loss on plan liabilities			
a) Amount	3.070	17	(1,996)
b) Percentage of present value of plan liabilities	4.09%	0.00%	(3.40%)

The cumulative amount of actuarial gains and losses recognised directly in *Other comprehensive income* amounted to NOK 16.3, NOK 10.9 and NOK 10.9 billion net of tax with a negative effect on *Other comprehensive income* in 2011, 2010 and 2009, respectively.

Assumptions used to determine benefit costs for the year in %	2011	2010
Discount rate	4.25	4.75
Expected return on plan assets	5.75	6.00
Rate of compensation increase	4.00	4.25
Expected rate of pension increase	2.75	3.00
Expected increase of social security base amount (G-amount)	3.75	4.00

Assumptions used to determine benefit obligations as of 31 December in %	2011	2010
Discount rate	3.25	4.25
Expected return on plan assets	4.75	5.75
Rate of compensation increase	3.00	4.00
Expected rate of pension increase	2.00	2.75
Expected increase of social security base amount (G-amount)	2.75	3.75

Average remaining service period in years	15	15
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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 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. Expected attrition at 31 December 2010 was 2.0%, 2.0%, 1.0%, 0.5% and 0.0% for the employees under 30 years, 30-39 years, 40-49 years, 50-59 years and 60-67 years, respectively.

The expected utilisation at 31 December 2011 of Statoil early retirement scheme is 40% for employees at 62 years, 20% for employees between 63-65 years and 30% for employees at 66 years. Expected utilisation at 31 December 2010 of Statoil early retirement scheme was 50% for employees at 62 years, and 30% for the remaining employees between 63-66 years.

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 adjustments reduce the mortality rate with a minimum of 15% for males and 10% for females for each employee. The disability table, KU, has been developed by the insurance company Storebrand and aligns with the actual disability risk for Statoil in Norway.

Below is shown a selection related to demographic assumptions used at 31 December 2011. The table shows the probability of disability or mortality, within one year, by age groups as well as expected lifetime.

Age	Disability in %		Mortality in %		Expected lifetime	
	Men	Women	Men	Women	Men	Women
20	0.12	0.15	0.02	0.02	82.46	85.24
40	0.21	0.35	0.09	0.05	82.74	85.47
60	1.48	1.94	0.75	0.41	84.02	86.31
80	N/A	N/A	6.69	4.31	89.26	90.29

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 2011. Actual results may materially deviate from these estimates.

(in NOK billion)	Discount rate		Rate of compensation increase		Social security base amount		Expected rate of pension increase	
	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%
Changes in:								
Projected benefit obligation at 31 December 2011	(7.33)	7.54	4.52	(4.40)	(0.13)	0.26	4.20	(4.14)
Service cost 2012	(0.59)	0.61	0.41	(0.40)	(0.02)	0.01	0.33	(0.33)

The estimated sensitivity of the financial results to each of the key assumption factors 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 2011 and 2010. 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 additional return above the money market's.

In its asset management, Statoil Pension aims at achieving long-term returns which contribute towards meeting future pension liabilities. Assets are managed to achieve a return as high as possible within a framework of public regulations and risk management policies. Statoil Pension's target returns require investments in assets with a higher risk than risk-free investments. Risk is reduced through maintaining a well-diversified asset portfolio. The assets are distributed across several asset classes to continuously maintain a diversified portfolio composition, both with regard to geography and individual securities.

Pension assets allocated on respective investments classes

(in %)	2011	2010
Equity securities	29.00	40.10
Bonds	43.70	38.10
Money market instruments	23.00	14.70
Real estate	4.00	4.90
Other assets	0.30	2.20
Total	100.00	100.00

Properties owned by Statoil Pension amounted to NOK billion 1.9 and NOK 2.3 billion of total pension assets at 31 December 2011 and 2010, 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 2012. The portfolio weight during a year will depend on the risk capacity.

Finance portfolio Statoil's pension funds

(All figures in %)	Portfolio weight ¹⁾		Expected rate of return
Equity securities	40.00	(+/- 5)	X + 4
Bonds	45.00	(+/- 5)	X
Money market instruments	15.00	(+/-15)	X - 0.2
Total finance portfolio	100.00		

1) The brackets express the scope of tactical deviation by Statoil Kapitalforvaltning ASA (the asset manager).

X) Long-term rate of return on debt securities.

The expected company contribution related to 2012 amounts to approximately NOK 3.3 billion.

8.1.24 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	Asset retirement obligations	Other provisions	Other liabilities	Total
Non-current portion at 31 December 2010	60,089	5,982	1,907	67,978
Long term interest bearing provisions reported as bonds, bank loans and finance lease liabilities	0	347	0	347
Current portion at 31 December 2010 reported as trade and other payables	828	2,482	0	3,310
Asset retirement obligation, other provisions and other liabilities at 31 December 2010	60,917	8,811	1,907	71,635
New provisions in the period	2,095	4,241	1,838	8,174
Transfer from provisions classified as held for sale	549	0	0	549
Revision in the estimates	2,824	1,400	221	4,445
Amounts charged against provisions	(621)	(2,835)	(50)	(3,506)
Effects of change in the discount rate	13,000	0	0	13,000
Reduction due to disposals	(497)	(2)	0	(499)
Accretion expenses	2,813	0	0	2,813
Reclassification and transfer	(1,637)	1,550	(336)	(423)
Currency translation	372	380	(6)	746
Asset retirement obligation, other provisions and other liabilities at 31 December 2011	79,815	13,545	3,574	96,934
Current portion at 31 December 2011 reported as trade and other payables	867	7,977	0	8,844
Long term interest bearing provisions reported as bonds, bank loans and finance lease liabilities	0	786	0	786
Non-current portion at 31 December 2011	78,948	4,782	3,574	87,304

Expected timing of cash outflows

(in NOK million)	Asset retirement obligations	Other provisions	Other liabilities	Total
2012 - 2018	13,796	11,065	2,625	27,486
2019 - 2023	10,501	34	201	10,736
2024 - 2028	5,474	443	0	5,917
2029 - 2033	24,752	0	0	24,752
Thereafter	25,292	2,003	748	28,043
At 31 December 2011	79,815	13,545	3,574	96,934

The timing of cash outflows related to Asset retirement obligation primarily depends on when the production ceases at the various facilities.

The discount rate used in the calculation of the Asset retirement obligation 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 Statoil's credit premium. The increase in Asset retirement obligation due to change in discount rate is related to a decrease in the risk free interest rates.

The increased estimate in asset retirement obligations has been added to property, plant and equipment and will increase depreciation expenses.

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*.

8.1.25 Trade and other payables

(in NOK million)	2011	At 31 December 2010	2009
Financial trade and other payables:			
Trade payables	31,123	23,234	17,554
Non-trade payables and accrued expenses	21,544	21,723	17,818
Liability joint ventures	19,827	13,623	13,430
Payables to equity accounted investments and other related parties	10,930	9,994	9,144
Total financial trade and other payables	83,424	68,574	57,946
Non-financial trade and other payables	10,543	5,146	2,104
Trade and other payables	93,967	73,720	60,050

Included in Non-trade payables and accrued expenses are certain provisions that are further described in note 28 *Other commitments and contingencies*.

For information regarding currency sensitivities, see note 31 *Financial instruments: fair value measurement and sensitivity analysis of market risk*.

Further information on payables to equity accounted investments and other related parties, see note 29 *Related parties*.

8.1.26 Bonds, bank loans, commercial papers and collateral liabilities

(in NOK million)	2011	At 31 December 2010	2009
Bank overdraft facilities	1,757	1,404	196
Collateral liabilities	10,843	5,680	4,654
Current portion of non-current bonds and bank loans	6,296	4,038	2,686
Current portion of finance lease obligations	872	589	582
Other	79	19	32
Bonds, bank loans, commercial papers and collateral liabilities	19,847	11,730	8,150
Weighted interest rate	1.65	2.45	2.24

Carrying amount for *Bonds, bank loans, commercial papers and collateral liabilities*, at amortised cost, and accrued interest approximate fair value.

Collateral liabilities relate to cash received as security for a portion of the Statoil's credit exposure.

At 31 December 2011 Statoil Fuel & Retail ASA has drawn NOK 0.2 billion on a revolving loan facility. The loan matured in January 2012. At 31 December 2010 Statoil Fuel & Retail ASA had drawn NOK 0.3 billion on the revolving loan facility.

8.1.27 Leases

Statoil leases certain assets, notably drilling rigs, vessels and office buildings.

Statoil has certain operational lease contracts for a number of drilling rigs as of 31 December 2011. The remaining significant contracts' terms range from six months to eight years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. Statoil's rig leases have been entered into in order to ensure drilling capacity for sanctioned projects and planned wells and to secure long-term strategic capacity for future exploration and production drilling. 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 below. However, for rig leases where the joint venture is the original lessee, Statoil only includes its proportional share of the rig lease.

In 2010 Statoil entered into a long term time charter agreement with Teekay for offshore loading and transport in the North Sea. The contract covers the lifetime of applicable producing fields and at year end 2011 includes six crude tankers. The contract's estimated nominal amount was approximately NOK 5.8 billion at year end 2011, and it has been accounted for as an operating lease. The estimated future leasing commitment depends on assumptions made concerning field production quantities and related life time, expected decrease in the number of vessels employed over time, as well as development in other factors impacting Statoil's payable amounts under the terms of the contract.

Statoil leases three LNG vessels on behalf of Statoil and the SDFI. Statoil accounts for the combined Statoil and SDFI share of these agreements as finance leases in the Consolidated balance sheet, and further accounts for the SDFI related portion as operating subleases. The finance leases included in the balance sheet reflect the original lease term of 20 years from 2006. In addition, Statoil has the option to extend the leases for two additional periods of five years each.

Statoil leases the Combined Heat and Power plant at Mongstad from DONG Energy. Statoil accounts for this agreement as a finance lease in the balance sheet, and the contract period is 20 years from commercial operation start up in 2010. At the end of the period Statoil has the option to either take title at no charge or extend the contract period to either 25 or 30 years.

Through its 60% participation in the Peregrino field in Brazil, Statoil is party to a leasing agreement with Maersk Peregrino Pte. Ltd. for a Floating Production, Storage and Offloading (FPSO) vessel for the production from the field. Statoil accounts for its 60% share of the lease arrangement as a finance lease. The lease term is 15 years starting from 2011, with options for the Peregrino partners to buy the vessel after 5 years and at annual intervals thereafter.

In 2011, net rental expenses were NOK 13.7 billion (NOK 12.4 billion in 2010 and NOK 10.9 billion in 2009) of which minimum lease payments were NOK 16.0 billion (NOK 13.8 billion in 2010 and NOK 12.7 billion in 2009) and sublease payments received were NOK 2.4 billion (NOK 1.5 billion in 2010 and NOK 1.8 billion in 2009). No material contingent rent payments have been expensed in 2011, 2010 or 2009.

The information in the table below shows future minimum lease payments due and receivable under non-cancellable leases at 31 December 2011. Amounts in the table related to finance leases include future minimum lease payments for assets recognised in the Consolidated financial statements at year end 2011.

(in NOK million)	Operating leases						Finance leases		
	Rigs	Vessels	Other leases	Total	Sublease	Net total	Minimum lease payments	Discount element	Net present value minimum lease payments
2012	16,623	3,228	1,601	21,452	(2,860)	18,592	1,343	(75)	1,268
2013	14,933	2,586	1,233	18,752	(2,005)	16,747	1,161	(129)	1,032
2014	9,710	1,952	1,105	12,767	(737)	12,030	1,150	(179)	971
2015	5,691	1,733	1,064	8,488	(403)	8,085	1,143	(230)	913
2016	3,244	1,421	946	5,611	(400)	5,211	1,117	(272)	845
Thereafter	5,199	3,396	8,198	16,792	(1,816)	14,976	10,033	(3,111)	6,922
Total future minimum lease payments	55,400	14,316	14,147	83,862	(8,221)	75,641	15,948	(3,996)	11,951

The column Subleases, under the section Operating leases, includes future operating lease payments from the SDFI related to the three above-mentioned LNG vessels. The section Other 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 operational lease commitments to a related party extend in time to the year 2034. NOK 4 billion of the total is payable after 2016.

Property, plant and equipment includes the following amounts for leases that have been capitalised at 31 December 2011, 2010 and 2009:

(in NOK million)	2011	2010	2009
Leased assets under development	0	0	8,983
Oil & Gas plants in production	6,706	0	0
Vessels	4,515	4,421	4,079
Refining and manufacturing plants	2,835	2,849	0
Other	433	1,646	797
Accumulated depreciation	(4,308)	(1,795)	(1,404)
Capitalised amount	10,181	7,121	12,455

8.1.28 Other commitments and contingencies

Contractual commitments

(in NOK million)	2012	2013	Thereafter	Total
Joint Venture related:				
Construction in progress	21,288	9,765	4,275	35,328
Property, plant and equipment and other investments	3,425	400	330	4,155
Subtotal joint venture related commitments	24,713	10,165	4,605	39,483
Non Joint Venture related:				
Construction in progress	220	0	0	220
Property, plant and equipment and other investments	315	32	30	377
Subtotal non joint venture related commitments	535	32	30	597
Total	25,248	10,197	4,635	40,080

The contractual commitments reflect Statoil's share and mainly comprise construction and acquisition of property, plant and equipment.

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 the group the obligation to pay for the agreed-upon service or commodity, irrespectively 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 the group 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 Statoil's ownership share).

Nominal minimum commitments at 31 December 2011:

(in NOK million)	Transport and terminal commitments	Refinery related commitments	Total
2012	13,411	738	14,149
2013	11,603	848	12,451
2014	11,522	781	12,303
2015	11,649	796	12,445
2016	11,500	805	12,305
Thereafter	84,809	15,960	100,769
Total	144,494	19,928	164,422

The above table outlines nominal minimum obligations for future years, and mainly includes commitments within Statoil's natural gas operations in addition to various other transport and similar commitments. Statoil has entered into pipeline transportation agreements for most of its prospective gas sales contracts. These agreements ensure the right to transport the production of gas through the pipelines, while also imposing an obligation to pay for booked capacity. The main transportation commitments are Statoil's booked capacity in Gassled and the sale of a 24.1% ownership share increased Statoil's external nominal minimum long term commitments by approximately NOK 80 billion.

Statoil has contractual commitments to the US-based energy company Dominion for terminal capacity at the Cove Point liquefied natural gas terminal in the USA. At year end 2011 the commitment includes an annual capacity of approximately 10.1 bcm for the period until the end of 2016, thereafter reduced to 4 bcm until the end of 2020, and finally reduced to 2.4 bcm for the remaining period ending September 2023. Such commitments have been included in full in the table above, but part of the commitment has been made on behalf of and for the account and risk of the SDFI. Statoil's and the SDFI's respective future shares of the Cove Point terminal capacity and related commitments depend on actual usage of the terminal. Statoil covers substantially all the costs of any unused capacity, while the costs of used capacity are split in proportion to the produced natural gas volumes of Statoil and the SDFI, respectively.

The Mongstad refinery has a long-term take-or-pay contract related to purchase of heat from the Troll licence partners. The contract term expires in 2040, and future expected minimum annual obligations under this contract represents the most significant part of Refinery related commitments included in the table above.

Guarantees

Statoil has guaranteed certain recoverable reserves of crude oil in the Veslefrikk field on the NCS as part of an asset exchange with Petro Canada in 1996. Under the guarantee, Statoil is obligated to deliver indemnity reserves to Petro Canada in the event that recoverable reserves prove lower than a specified volume. At year end 2011 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 1.5 billion. A provision of NOK 0.8 billion has been recognised at year end related to this guarantee.

During Statoil's previous full ownership of the Peregrino field, the parent company Statoil ASA provided a payment guarantee to the lessor of certain production facilities located on the field. Following the sale of 40% of the field in 2011 Statoil formally remains guarantor for the full lease amount, but has obtained a counter indemnity deed from the ultimate owner of our partner on the field for the 40% share of the original payment guarantee. Field re-possession rights in case of partner default further decreases the risk for Statoil. The 40% share of the payment guarantee however represents a financial guarantee for Statoil, with an estimated maximum exposure of USD 0.6 billion at year end 2011, while both its carrying value and fair value are immaterial. Reference is also made to applicable tables in note 30 *Financial instruments by category*.

Under the Norwegian public limited companies act section 14-11, Statoil and Norsk Hydro are jointly and severally liable for certain guarantee commitments entered into by Norsk Hydro prior to the merger between Statoil and Hydro Petroleum in 2007. The total amount Statoil is jointly liable for is approximately NOK 1.0 billion. As of the current date, the probability that these guarantee commitments will impact Statoil is deemed to be remote. No liability has been recognised in the Consolidated financial statements at year end 2011.

Other commitments and contingencies

As a condition for being awarded oil and gas exploration and production licenses, participants may be committed to drill a certain number of wells. At the end of 2011, Statoil was committed to participate in 15 wells in Norway and 30 wells outside Norway, with an average ownership interest of approximately 43%. Statoil's share of estimated expenditures to drill these wells amounts to approximately NOK 7.6 billion. Additional wells that Statoil may become committed to participating in depending on future discoveries in certain licenses are not included in these numbers.

On the basis of 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 2009. 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 2011, the exposure for Statoil at year-end 2011 is estimated to be approximately USD 0.6 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 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 in tract two of the unitised Agbami field (Oil Mining Lease (OML) 128) concerning interpretation of the terms of the OML 128 Production Sharing Contract (PSC). The dispute relates to the right to cost recovery for certain costs and calculation of tax oil volumes, which are lifted by NNPC on behalf of the Nigerian government, and consequently the allocation between NNPC and the other OML 128 parties of cost oil, tax oil and profit oil volumes. NNPC claims that in the aggregate for 2009, 2010 and 2011, Statoil has lifted excess volumes which should be refunded to NNPC in order to comply with the PSC terms. Statoil disputes NNPC's position. Arbitration has been initiated in the matter under 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. The exposure for Statoil at year-end 2011 is mainly related to cost oil and profit oil volumes and have been estimated to the equivalent of approximately USD 0.5 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 revenue reduction.

A number of Statoil's long term gas sales agreements contain price review clauses. Certain counterparties have requested arbitration related to price review claims. The exposure for Statoil in this connection has been estimated to an amount equivalent to approximately NOK 3 billion related to gas deliveries prior to year end 2011. Statoil has provided for its best estimate for these contractual gas price disputes in the financial statements, with the related impact reflected as revenue reduction in the Consolidated statement of income.

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 the Company's best judgement. 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, refer to note 24 *Asset retirement obligations, other provisions and other liabilities*.

8.1.29 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 2011 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet (Norwegian national insurance fund) of 3.41%). 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.

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 SDFI 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. These sales, and related expenditures refunded by the State, are presented net in Statoil's Consolidated financial statements. Sales made by Statoil subsidiaries in their own name, and related expenditure, are however presented gross in Statoil's 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 State's share of profit or loss is reflected in Statoil's *Selling, general and administrative expenses* as expenses or reduction of expenses, respectively. The following purchases were made from the SDFI for the years presented:

Total purchases of oil and natural gas liquids from the Norwegian State amounted to NOK 95.5 billion (161 million barrels oil equivalents), NOK 81.4 billion (176 million barrels oil equivalents) and NOK 74.3 billion (204 million barrels oil equivalents) in 2011, 2010 and 2009, respectively. Purchases of natural gas regarding Tjelbergodden methanol plant from the Norwegian State amounted to NOK 0.4 billion, NOK 0.4 billion and NOK 0.3 billion in 2011, 2010 and 2009, respectively. The major part included in the line item payables to equity accounted investments and other related parties in note 25 *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 statements of income.

For information concerning certain lease arrangements with Statoil Pension, see note 27 *Leases*.

Compensation of key management personnel

The remuneration to key management personnel (members of board of directors and the corporate executive committee) during the year was as follows:

(in NOK thousand)	2011	2010	2009
Current employee benefits	59,391	49,856	50,573
Post-employment benefits	11,958	11,414	11,391
Other non-current benefits	149	95	137
Share based payment benefits	1,021	840	444
Total	72,519	62,205	62,545

At 31 December 2011 there are no loans to key management personnel.

8.1.30 Financial instruments by category

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 22 *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 million)	Note	Loans and receivables	Available- for sale	Hedge accounting	Fair value through profit or loss		Non-financial assets	Total carrying amount
					Held for trading	Fair value option		
31 December 2011								
Assets								
Non-current financial investments	16	0	2,859	0	0	12,526	0	15,385
Non-current derivative financial instruments	31	0	0	0	32,723	0	0	32,723
Prepayments and financial receivables	16	1,605	0	0	0	0	1,738	3,343
Trade and other receivables	18	94,663	0	0	0	0	8,598	103,261
Current derivative financial instruments	31	0	0	3	6,007	0	0	6,010
Current financial investments	19	0	50	0	14,744	5,084	0	19,878
Cash and cash equivalents	20	40,596	0	0	0	0	0	40,596
Total		136,864	2,909	3	53,474	17,610	10,336	221,196

(in NOK million)	Note	Loans and receivables	Available- for-sale	Hedge accounting	Fair value through profit or loss		Non-financial assets	Total carrying amount
					Held for trading	Fair value option		
31 December 2010								
Assets								
Non-current financial investments	16	0	3,042	0	0	12,315	0	15,357
Non-current derivative financial instruments	31	0	0	0	20,563	0	0	20,563
Prepayments and financial receivables	16	1,752	0	0	0	0	2,193	3,945
Trade and other receivables	18	68,448	0	0	0	0	6,362	74,810
Current derivative financial instruments	31	0	0	0	6,074	0	0	6,074
Current financial investments	19	0	0	0	5,347	6,162	0	11,509
Cash and cash equivalents	20	30,521	0	0	0	0	0	30,521
Total		100,721	3,042	0	31,984	18,477	8,555	162,779

(in NOK million)	Note	Loans and receivables	Available- for-sale	Hedge accounting	Fair value through profit or loss		Non-financial assets	Total carrying amount
					Held for trading	Fair value option		
31 December 2009								
Assets								
Non-current financial investments	16	0	2,223	0	0	11,044	0	13,267
Non-current derivative financial instruments	31	0	0	0	17,644	0	0	17,644
Prepayments and financial receivables	16	1,624	0	0	0	0	2,583	4,207
Trade and other receivables	18	53,050	0	0	0	0	5,942	58,992
Current derivative financial instruments	31	0	0	0	5,369	0	0	5,369
Current financial investments	19	55	0	0	1,962	5,005	0	7,022
Cash and cash equivalents	20	25,286	0	0	0	0	0	25,286
Total		80,015	2,223	0	24,975	16,049	8,525	131,787

(in NOK million)	Note	Hedge accounting	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2011						
Liabilities						
Bonds, bank loans and finance lease liabilities	22	0	110,825	0	786	111,611
Non-current derivative financial instruments	31	0	0	3,904	0	3,904
Trade and other payables	25	0	83,424	0	10,543	93,967
Bonds, bank loans, commercial papers and collateral liabilities	26	0	19,847	0	0	19,847
Current derivative financial instruments	31	1	0	3,018	0	3,019
Total		1	214,096	6,922	11,329	232,348

(in NOK million)	Note	Hedge accounting	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2010						
Liabilities						
Bonds, bank loans and finance lease liabilities	22	0	99,797	0	0	99,797
Non-current derivative financial instruments	31	0	0	3,386	0	3,386
Trade and other payables	25	0	68,574	0	5,146	73,720
Bonds, bank loans, commercial papers and collateral liabilities	26	0	11,730	0	0	11,730
Current derivative financial instruments	31	0	0	4,161	0	4,161
Total		0	180,101	7,547	5,146	192,794

(in NOK million)	Note	Hedge accounting	Amortised cost	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2009						
Liabilities						
Bonds, bank loans and finance lease liabilities	22	0	95,962	0	0	95,962
Non-current derivative financial instruments	31	0	0	1,657	0	1,657
Trade and other payables	25	0	57,946	0	2,104	60,050
Bonds, bank loans, commercial papers and collateral liabilities	26	0	8,150	0	0	8,150
Current derivative financial instruments	31	0	0	2,860	0	2,860
Total		0	162,058	4,517	2,104	168,679

The following tables present amounts recognised in the Consolidated statement of income related to Statoil's financial instruments.

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2011								
Net operating income	10,497	0	0	0	0	0	201,287	211,784
Net financial items								
Net foreign exchange gains (losses)	3,255	0	0	(1,315)	(1,575)	0	0	365
Interest income	1,495	0	308	955	0	0	0	2,758
Other financial items	(1,158)	0	(379)	70	0	16	0	(1,451)
Interest income and other financial items	337	0	(71)	1,025	0	16	0	1,307
Interest expenses	2,469	0	0	65	(5,602)	0	0	(3,068)
Impairment loss recognised	0	0	0	0	0	(495)	0	(495)
Other financial expenses	6,765	0	0	1	157	0	(2,975)	3,948
Interest and other financial expenses	9,234	0	0	66	(5,445)	(495)	(2,975)	385
Net financial items	12,826	0	(71)	(224)	(7,020)	(479)	(2,975)	2,057
Income before tax	23,323	0	(71)	(224)	(7,020)	(479)	198,312	213,841

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2010								
Net operating income	(3,450)	0	0	0	0	0	140,711	137,261
Net financial items								
Net foreign exchange gains (losses)	(5,451)	0	0	1,497	2,128	0	0	(1,826)
Interest income	1,146	0	314	846	0	0	0	2,306
Other financial items	(134)	0	861	17	0	50	13	807
Interest income and other financial items	1,012	0	1,175	863	0	50	13	3,113
Interest expenses	2,448	0	0	0	(4,150)	0	0	(1,702)
Impairment loss recognised	0	0	0	0	0	0	0	0
Other financial expenses	2,363	0	0	0	254	0	(2,637)	(20)
Interest and other financial expenses	4,811	0	0	0	(3,896)	0	(2,637)	(1,722)
Net financial items	372	0	1,175	2,360	(1,768)	50	(2,624)	(435)
Income before tax	(3,078)	0	1,175	2,360	(1,768)	50	138,087	136,826

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans and receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2009								
Net operating income	12,337	0	0	0	0	(159)	109,491	121,669
Net financial items								
Net foreign exchange gains (losses)	16,661	0	0	(10,572)	(4,076)	0	(24)	1,989
Interest income	1,290	0	326	1,088	0	0	0	2,704
Other financial items	518	0	403	111	0	(28)	0	1,004
Interest income and other financial items	1,808	0	729	1,199	0	(28)	0	3,708
Interest expenses								
Interest expenses	2,123	0	0	0	(3,748)	0	0	(1,625)
Impairment loss recognised	0	0	0	0	0	(1,404)	0	(1,404)
Other financial expenses	(6,807)	0	0	0	(188)	0	(2,432)	(9,427)
Interest and other financial expenses	(4,684)	0	0	0	(3,936)	(1,404)	(2,432)	(12,456)
Net financial items	13,785	0	729	(9,373)	(8,012)	(1,432)	(2,456)	(6,759)
Income before tax	26,122	0	729	(9,373)	(8,012)	(1,591)	107,035	114,910

8.1.31 Financial instruments: fair value measurement and sensitivity analysis of market risk

Fair value measurement of financial instruments

Derivative financial instruments

Statoil measures all derivative financial instruments 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.

When determining fair value of derivative financial instruments Statoil uses prices quoted in an active market to the extent possible. 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, see note 2 *Significant accounting policies*.

The following table contains the estimated fair values and net carrying amounts of Statoil's derivative financial instruments. Of the total ending balance at 31 December 2011 NOK 21.4 billion relates to certain earn-out agreements and embedded derivatives recognised as derivative financial instruments in accordance with IAS 39. At the end of 2010 the estimated fair value of these agreements was NOK 15.1 billion.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
At 31 December 2011			
Debt-related instruments	14,493	(4,159)	10,334
Non-debt-related instruments	160	(1,349)	(1,189)
Crude oil and refined products	14,437	(468)	13,969
Natural gas and electricity	9,643	(947)	8,696
Total	38,733	(6,923)	31,810
At 31 December 2010			
Debt-related instruments	8,404	(3,631)	4,773
Non-debt-related instruments	1,520	(106)	1,414
Crude oil and refined products	10,187	(691)	9,496
Natural gas and electricity	6,526	(3,119)	3,407
Total	26,637	(7,547)	19,090
At 31 December 2009			
Debt-related instruments	6,405	(1,708)	4,697
Non-debt-related instruments	347	(867)	(520)
Crude oil and refined products	8,034	(842)	7,192
Natural gas and electricity	8,227	(1,100)	7,127
Total	23,013	(4,517)	18,496

Financial investments

Statoil measures all financial investments at fair value. Statoil's financial investments consist of the portfolios held by the group'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 fair value of financial investments, the group uses prices quoted in an active market to the extent possible. This will typically be for listed equity securities and government bonds. Where there is no active market, fair value is determined using valuation techniques such as discounted cash flow analysis. For more information about methodology and assumptions used when measuring fair value of the Statoil's financial investments see note 2 *Significant accounting policies*. For information about fair values of the group's financial investments recognised in the balance sheet see note 16 *Non-current financial assets and prepayments* and note 19 *Current financial investments*.

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 million)	Non-current financial investment	Non-current derivative financial instruments- assets	Current financial investments	Current derivative financial instruments- assets	Non-current derivative financial instruments- liabilities	Current derivative financial instruments- liabilities	Net fair value
At 31 December 2011							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	7,882	0	4,518	0	0	0	12,400
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	4,844	15,003	15,360	4,486	(3,904)	(3,019)	32,770
Fair value based on unobservable inputs (Level 3)	2,659	17,720	0	1,524	0	(0)	21,903
Total fair value	15,385	32,723	19,878	6,010	(3,904)	(3,019)	67,073
At 31 December 2010							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	8,182	0	4,939	0	0	0	13,121
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	4,396	6,798	6,570	4,667	(3,386)	(4,154)	14,891
Fair value based on unobservable inputs (Level 3)	2,779	13,765	0	1,407	0	(7)	17,944
Total fair value	15,357	20,563	11,509	6,074	(3,386)	(4,161)	45,956
At 31 December 2009							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	6,663	0	4,339	42	0	(18)	11,026
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	4,683	6,191	2,683	3,827	(1,657)	(2,756)	12,971
Fair value based on unobservable inputs (Level 3)	1,921	11,453	0	1,500	0	(86)	14,788
Total fair value	13,267	17,644	7,022	5,369	(1,657)	(2,860)	38,785

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 the group 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 reasonably 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 2.5 billion at end of 2011 and increased by NOK 0.1 billion at end of 2010 and impacted the Consolidated statement of income with corresponding amounts.

The reconciliation of the changes in fair value during 2011, 2010 and 2009 for all financial assets and liabilities classified in the third level in the hierarchy are presented in the following table.

(in NOK million)	Non-current financial investment	Non-current derivative financial instruments-assets	Current derivative financial instruments- assets	Non-current derivative financial instruments-liabilities	Current derivative financial instruments- liabilities
For the year ended 31 December 2011					
Opening balance	2,779	13,765	1,407	0	(7)
Total gains and losses recognised					
- in statement of income	(515)	5,528	1,524	0	7
- in other comprehensive income	(197)	0	0	0	0
Purchases	673	0	0	0	0
Settlement	(30)	0	(1,361)	0	0
Transfer into level 3	0	0	0	0	0
Transfer out of level 3	(1)	(1,517)	(43)	0	0
Foreign currency translation differences	(50)	(56)	(3)	0	0
Closing balance	2,659	17,720	1,524	0	0
For the year ended 31 December 2010					
Opening balance	1,921	11,453	1,500	0	(86)
Total gains and losses recognised					
- in statement of income	(4)	2,312	1,407	0	(7)
- in other comprehensive income	213	0	0	0	0
Purchases	634	0	0	0	0
Settlement	(22)	0	(1,500)	0	86
Transfer into level 3	(10)	0	0	0	0
Transfer out of level 3	47	0	0	0	0
Closing balance	2,779	13,765	1,407	0	(7)
For the year ended 31 December 2009					
Opening balance	3,488	8,852	1,319	(760)	(91)
Total gains and losses recognised					
- in statement of income	(1,499)	2,601	1,500	760	(86)
- in other comprehensive income	0	0	0	0	0
Purchases	941	0	0	0	0
Settlement	(327)	0	(1,319)	0	91
Transfer into level 3	307	0	0	0	0
Transfer out of level 3	(989)	0	0	0	0
Closing balance	1,921	11,453	1,500	0	(86)

The assets and liabilities within the level 3 have during 2011 had a net increase in the fair value of NOK 4.0 billion. Of the NOK 6.5 billion recognised in the Consolidated statement of income during 2011 NOK 4.2 billion are related to changes in fair value of certain earn-out agreements. Related to the same earn-out agreements NOK 1.3 billion included in the opening balance for 2011 have been fully realised as the underlying volumes have been delivered during 2011 and the amount is presented as settled in the above table.

By end of 2011 the fair value of NOK 1.6 billion for derivative financial instruments has been transferred out of level 3 and into level 2. This because the significant portion of the fair value now is calculated based on inputs from observable market transaction and not internal assumptions.

Practically all gains and losses recognised in the Consolidated statement of income during 2011 are related to assets and liabilities held by Statoil at the end of 2011.

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 the group manages these risks see note 7 *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 balance sheet.

Price risk sensitivities by end of 2011 have been calculated assuming a reasonably possible change of 40% in crude oil, refined products, electricity and natural gas prices. By end of 2010 and 2009 the price risk sensitivities were calculated assuming a reasonably possible change of 30% in crude oil, refined products and electricity prices, and 50% change for 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 million)	Net fair value	-40% sensitivity	40% sensitivity
At 31 December 2011			
Crude oil and refined products	13,969	(9,425)	9,431
Natural gas and electricity	8,696	2,915	(2,887)
		-30% sensitivity	30% sensitivity
At 31 December 2010			
Crude oil and refined products	9,496	(2,762)	2,762
		-50%/-30% sensitivity	50%/30% sensitivity
At 31 December 2010			
Natural gas and electricity	3,407	3,680	(3,666)
		-30% sensitivity	30% sensitivity
At 31 December 2009			
Crude oil and refined products	7,192	(2,087)	1,580
		-50%/-30% sensitivity	50%/30% sensitivity
At 31 December 2009			
Natural gas and electricity	7,127	3,871	(3,886)

As part of the tools to monitor and manage risk, the group uses the value at risk (VaR) method for certain parts of its commodity trading activity within the Marketing, Processing and Renewable (MPR) segment.

The Crude oil, liquids and products (CLP) cluster within MPR uses the historical simulation method where daily percentage market price and volatility changes for all significant products in the CLP portfolio over a given time period are applied to the current portfolio value, in order to estimate a probability distribution of future market value changes for the portfolio. Non-linear instruments such as options are remeasured on a daily basis over the simulation interval using the historical price and volatility inputs; and the daily historical value changes are an integral part of the portfolio value changes. The relationship between VaR estimates and actual portfolio value changes are monitored on a monthly basis using a four years rolling observation window and input parameters such as simulation intervals are recalibrated when model performance moves outside acceptable bounds.

The Natural gas cluster within MPR mainly measures its market risk exposure using a variance/covariance VaR method. Furthermore a 95% confidence interval and a one day holding period is applied. The variance/covariance method is applied to the current portfolio in order to quantify portfolio movements caused by possible future changes in the market prices over a 24-hour holding period. The variance/covariance method calculates the VaR as a function of standard deviation per instrument in the portfolio and the correlation between the instruments. The practical understanding is that there is a 95% probability that the value of the portfolio will change by less than the calculated VaR number during the next trading day. VaR does not quantify the worst case loss.

The variance/covariance method calculates the VaR as a function of the standard deviation per instrument in the portfolio and the correlation between the instruments. The historical simulation method derives daily percentage market price and volatility changes for all significant products in the portfolio over a given time period and apply those to the current portfolio value, in order to estimate a probability distribution of future market value changes for the portfolio. Different VaR-methods are used within CLP and the Natural gas cluster to best reflect the nature of the relevant commodity markets.

Within CLP all physical and financial contracts that are managed together for risk management purposes are subject to VaR limits, independently of how they are recognised in Statoil's Consolidated balance sheet. Within Natural gas embedded derivatives as well as certain physical forward contracts recognised as derivative financial instrument that are not held as part of a trading position are not included in the portfolio subject to VaR limits.

The calculated VaR numbers for 2011, 2010 and 2009 and a summary of the assumptions used are presented in the following table.

(in NOK million)	High	Low	Average
For the year ended 31 December 2011			
Crude Oil and Refined Products	195	45	91
Natural Gas and Electricity	198	63	105
For the year ended 31 December 2010			
Crude Oil and Refined Products	151	59	105
Natural Gas and Electricity	300	6	116
For the year ended 31 December 2009			
Crude Oil and Refined Products	189	42	103
Natural Gas and Electricity	219	8	80

Assumptions used	Method used	Confidence level	Holding period
Crude Oil and Refined Products	Historical simulation VaR	95%	1 day
Natural Gas and Electricity	Variance/Covariance	95%	1 day

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 the group manages these risks see note 7 *Financial risk management*.

The following currency risk sensitivities have been calculated by assuming a 12% reasonably possible change in foreign exchange rates that the group is exposed to. An increase in the foreign exchange rates by 12% means that the transaction currency has strengthened in value.

(in NOK million)	USD	EUR	GBP	CAD	NOK	SEK	DKK
At 31 December 2011							
Net gains/losses (12% sensitivity)	(10,444)	1,406	919	(72)	8,025	67	88
Net gains/losses (-12% sensitivity)	10,444	(1,406)	(919)	72	(8,025)	(67)	(88)
At 31 December 2010							
Net gains/losses (12% sensitivity)	(12,215)	826	(339)	88	11,239	371	134
Net gains/losses (-12% sensitivity)	12,215	(826)	339	(88)	(11,239)	(371)	(134)
At 31 December 2009							
Net gains/losses (12% sensitivity)	(9,999)	746	818	(299)	7,354	558	819
Net gains/losses (-12% sensitivity)	9,999	(746)	(818)	299	(7,354)	(558)	(819)

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 the group manages these risks, see note 7 *Financial risk management*.

For the interest rate risk sensitivity a change of 1.5 percentage point in the interest rates have been used as reasonably possible changes in the calculation by end of 2011 and 2009. By end of 2010 a decline of 0.5 percentage point and an increase 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 increases that would impact the Consolidated statement of income are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2011		
Interest rate risk (1.5 percentage point sensitivity)	10,214	(10,214)
At 31 December 2010		
Interest rate risk (-0.5 percentage point sensitivity)	2,785	
Interest rate risk (1.5 percentage point sensitivity)		(8,355)
At 31 December 2009		
Interest rate risk (1.5 percentage point sensitivity)	8,456	(8,456)

Equity risk

The following table contains the fair value and related equity price risk sensitivity of Statoil's listed and non-listed equity securities. The equity price risk sensitivity has been calculated based on what Statoil views to be reasonably possible changes in the equity prices for the coming year. For the listed securities a 20% change in the equity prices has been used in the calculation of the sensitivity for 2011, 2010 and 2009. For the non-listed securities a 40% change in the equity prices has been used in the calculation of the sensitivity for 2011 and 2009 while a change of 35% was used at the end of 2010.

For the listed equity securities changes in fair values would be recognised as gains or losses in the Consolidated statement of income. While for the non-listed equity securities that are classified as available for sale assets, a decline in the fair value would be recognised in the Consolidated statement of income as an impairment loss, while an increase in the fair value would be recognised in Other comprehensive income.

(in NOK million)	Fair value	-20% sensitivity	20% sensitivity
At 31 December 2011			
Listed equity securities	4,539	(905)	905
At 31 December 2010			
Listed equity securities	5,102	(1,020)	1,020
At 31 December 2009			
Listed equity securities	4,318	(864)	864
		-40% sensitivity	40% sensitivity
At 31 December 2011			
Non-listed equity securities	2,859	(1,143)	1,143
		-35% sensitivity	35% sensitivity
At 31 December 2010			
Non-listed equity securities	3,042	(1,065)	1,065
		-40% sensitivity	40% sensitivity
At 31 December 2009			
Non-listed equity securities	2,223	(889)	889

8.1.32 Condensed consolidating financial information related to guaranteed debt securities

Statoil Petroleum AS 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 issue future US registered debt securities from time to time for which debt securities Statoil Petroleum AS will be the co-obligor or guarantor.

The following financial information on a condensed consolidating basis provides investors with 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 the 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 proportional consolidated entities are accounted for using the equity method as required by Rule 3-10.

The following is condensed consolidated financial information as of 31 December, 2011 and 2010 and for the years ended 31 December 2011, 2010 and 2009.

CONSOLIDATED STATEMENT OF INCOME

2011 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	462,619	248,648	210,832	(276,500)	645,599
Net income from associated companies	70,523	11,107	4,324	(84,690)	1,264
Other income	74	8,848	14,420	0	23,342
Total revenues and other income	533,216	268,603	229,576	(361,190)	670,205
OPERATING EXPENSES					
Purchases [net of inventory variation]	(449,765)	(8,252)	(134,490)	272,902	(319,605)
Operating expenses	(9,153)	(34,062)	(21,212)	4,008	(60,419)
Selling, general and administrative expenses	(2,876)	(1,169)	(9,572)	409	(13,208)
Depreciation, amortisation and net impairment losses	(761)	(30,745)	(19,844)	0	(51,350)
Exploration expenses	(762)	(5,135)	(7,942)	0	(13,839)
Total operating expenses	(463,317)	(79,363)	(193,060)	277,319	(458,421)
Net operating income	69,899	189,240	36,516	(83,871)	211,784
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	3,833	483	(5,527)	1,576	365
Interest income and other financial items	3,421	1,173	2,054	(5,341)	1,307
Interest and other finance expenses	1,877	(5,582)	(1,251)	5,341	385
Net financial items	9,131	(3,926)	(4,724)	1,576	2,057
Income before tax	79,030	185,314	31,792	(82,295)	213,841
Income tax	(1,820)	(125,794)	(7,772)	(12)	(135,398)
Net income	77,210	59,520	24,020	(82,307)	78,443

CONSOLIDATED STATEMENT OF INCOME

2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	384,578	198,574	182,675	(238,877)	526,950
Net income from associated companies	37,378	(3,296)	923	(33,837)	1,168
Other income	12	994	1,201	(410)	1,797
Total revenues and other income	421,968	196,272	184,799	(273,124)	529,915
OPERATING EXPENSES					
Purchases [net of inventory variation]	(368,465)	(6,701)	(111,375)	229,105	(257,436)
Operating expenses	(9,575)	(34,576)	(16,930)	3,411	(57,670)
Selling, general and administrative expenses	(6,014)	(608)	(11,191)	6,732	(11,081)
Depreciation, amortisation and net impairment losses	(796)	(27,825)	(22,073)	0	(50,694)
Exploration expenses	(786)	(5,497)	(9,490)	0	(15,773)
Total operating expenses	(385,636)	(75,207)	(171,059)	239,248	(392,654)
Net operating income	36,332	121,065	13,740	(33,876)	137,261
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	(2,553)	725	27	(25)	(1,826)
Interest income and other financial items	4,677	786	4,654	(7,004)	3,113
Interest and other finance expenses	(420)	(3,943)	(2,601)	5,242	(1,722)
Net financial items	1,704	(2,432)	2,080	(1,787)	(435)
Income before tax	38,036	118,633	15,820	(35,663)	136,826
Income tax	1,833	(90,274)	(10,726)	(12)	(99,179)
Net income	39,869	28,359	5,094	(35,675)	37,647

CONSOLIDATED STATEMENT OF INCOME

2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	313,684	195,318	155,782	(202,265)	462,519
Net income from associated companies	28,187	(3,693)	2,992	(26,029)	1,457
Other income	5	1,121	248	0	1,374
Total revenues and other income	341,876	192,746	159,022	(228,294)	465,350
OPERATING EXPENSES					
Purchases [net of inventory variation]	(294,442)	(5,276)	(93,256)	187,104	(205,870)
Operating expenses	(10,649)	(34,979)	(13,361)	2,015	(56,974)
Selling, general and administrative expenses	(7,928)	(610)	(12,112)	10,329	(10,321)
Depreciation, amortisation and net impairment losses	(814)	(27,316)	(25,700)	0	(53,830)
Exploration expenses	(861)	(5,187)	(10,638)	0	(16,686)
Total operating expenses	(314,694)	(73,368)	(155,067)	199,448	(343,681)
Net operating income	27,182	119,378	3,955	(28,846)	121,669
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	10,608	(4,632)	2,998	(6,985)	1,989
Interest income and other financial items	4,693	1,017	(9,995)	7,993	3,708
Interest and other finance expenses	(10,629)	(4,118)	(5,064)	7,355	(12,456)
Net financial items	4,672	(7,733)	(12,061)	8,363	(6,759)
Income before tax	31,854	111,645	(8,106)	(20,483)	114,910
Income tax	(6,556)	(88,266)	(3,161)	788	(97,195)
Net income	25,298	23,379	(11,267)	(19,695)	17,715

CONSOLIDATED BALANCE SHEET

At 31 December 2011 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
<i>Non-current assets</i>					
Property, plant and equipment	5,404	215,531	186,650	0	407,585
Intangible assets	184	7,695	84,795	0	92,674
Shares in subsidiaries	351,881	111,675	0	(463,556)	0
Investments in associated companies	384	1,306	7,527	0	9,217
Deferred tax assets	3,637	0	2,067	0	5,704
Pension assets	3,865	0	23	0	3,888
Financial investments	2	5	15,378	0	15,385
Derivative financial instruments	15,122	17,601	0	0	32,723
Prepayments and financial receivables	1,298	1,004	1,041	0	3,343
Financial receivables from subsidiaries	70,145	105	160	(70,410)	0
Total non-current assets	451,922	354,922	297,641	(533,966)	570,519
<i>Current assets</i>					
Inventories	13,168	0	18,627	(4,025)	27,770
Trade and other receivables	53,241	25,458	24,918	(356)	103,261
Current tax receivables	0	0	573	0	573
Receivables from subsidiaries	18,338	34,299	84,522	(137,159)	0
Derivative financial instruments	4,118	1,550	342	0	6,010
Financial investments	14,620	0	5,258	0	19,878
Cash and cash equivalents	28,108	0	12,488	0	40,596
Total current assets	131,593	61,307	146,728	(141,540)	198,088
TOTAL ASSETS	583,515	416,229	444,369	(675,506)	768,607

CONSOLIDATED BALANCE SHEET

At 31 December 2011 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
<i>Equity</i>					
Statoil shareholders' equity	280,679	133,016	331,688	(466,467)	278,916
Non-controlling interest	0	0	6,239	0	6,239
Total equity	280,679	133,016	337,927	(466,467)	285,155
<i>Non-current liabilities</i>					
Bonds, bank loans and finance lease liabilities	98,273	762	12,576	0	111,611
Non-current liabilities to subsidiaries	78	68,619	1,712	(70,409)	(0)
Derivative financial instruments	3,904	0	0	0	3,904
Deferred tax liabilities	30	72,926	10,669	(1,105)	82,520
Pension liabilities	25,982	0	1,002	0	26,984
Asset retirement obligations, other provisions and other liabilities	2,233	63,066	22,224	(219)	87,304
Total non-current liabilities	130,500	205,373	48,183	(71,733)	312,323
<i>Current liabilities</i>					
Trade and other payables	41,184	16,672	36,258	(147)	93,967
Current tax payable	889	50,412	2,995	0	54,296
Bonds, bank loans, commercial papers and collateral liabilities	14,584	0	5,263	0	19,847
Derivative financial instruments	2,752	0	267	0	3,019
Current liabilities to subsidiaries	112,927	10,756	13,476	(137,159)	(0)
Total current liabilities	172,336	77,840	58,259	(137,306)	171,129
Total liabilities	302,836	283,213	106,442	(209,039)	483,452
TOTAL EQUITY AND LIABILITIES	583,515	416,229	444,369	(675,506)	768,607

CONSOLIDATED BALANCE SHEET

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
<i>Non-current assets</i>					
Property, plant and equipment	5,096	210,892	135,590	0	351,578
Intangible assets	15	7,774	35,382	0	43,171
Shares in subsidiaries	298,670	84,419	0	(383,089)	0
Investments in associated companies	0	1,301	7,696	0	8,997
Deferred tax assets	2,922	0	1,878	(2,922)	1,878
Pension assets	5,087	0	178	0	5,265
Financial investments	10	5	15,342	0	15,357
Derivative financial instruments	8,360	12,203	0	0	20,563
Prepayments and financial receivables	1,480	1,315	1,150	0	3,945
Financial receivables from subsidiaries	88,346	93	32,813	(121,252)	0
Total non-current assets	409,986	318,002	230,029	(507,263)	450,754
<i>Current assets</i>					
Inventories	15,021	0	12,596	(3,990)	23,627
Trade and other receivables	45,221	10,124	19,986	(521)	74,810
Current tax receivables	343	450	284	0	1,076
Receivables from subsidiaries	16,797	35,800	146,738	(199,335)	0
Derivative financial instruments	4,320	1,361	393	0	6,074
Financial investments	5,230	0	6,279	0	11,509
Cash and cash equivalents	18,131	0	12,390	0	30,521
Total current assets	105,063	47,734	198,666	(203,846)	147,617
Assets classified as held for sale	0	0	44,890	0	44,890
TOTAL ASSETS	515,049	365,736	473,585	(711,109)	643,261

CONSOLIDATED BALANCE SHEET

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
<i>Equity</i>					
Statoil shareholders' equity	221,303	102,208	281,994	(385,963)	219,542
Non-controlling interest	0	0	6,853	0	6,853
Total equity	221,303	102,208	288,847	(385,963)	226,395
<i>Non-current liabilities</i>					
Bonds, bank loans and finance lease liabilities	90,190	350	9,257	0	99,797
Non-current liabilities to subsidiaries	63	69,810	51,377	(121,250)	0
Derivative financial instruments	3,386	0	0	0	3,386
Deferred tax liabilities	0	76,260	4,913	(3,108)	78,065
Pension liabilities	21,497	0	615	0	22,112
Asset retirement obligations, other provisions and other liabilities	1,217	50,039	17,055	(333)	67,978
			0		
Total non-current liabilities	116,353	196,459	83,217	(124,691)	271,338
<i>Current liabilities</i>					
Trade and other payables	33,803	14,449	25,656	(188)	73,720
Current tax payable	0	42,761	4,862	(929)	46,694
Bonds, bank loans, commercial papers and collateral liabilities	9,749	9	1,972	0	11,730
Derivative financial instruments	3,863	21	277	0	4,161
Current liabilities to subsidiaries	129,978	9,829	59,531	(199,338)	0
Total current liabilities	177,393	67,069	92,298	(200,455)	136,305
Liabilities directly associated with the assets classified as held for sale	0	0	9,223	0	9,223
Total liabilities	293,746	263,528	184,738	(325,146)	416,866
TOTAL EQUITY AND LIABILITIES	515,049	365,736	473,585	(711,109)	643,261

CASH FLOW STATEMENT

At 31 December 2011 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by (used in) operating activities	30,489	81,811	29,319	(30,156)	111,463
Cash flows provided by (used in) investing activities	(8,040)	(61,888)	(43,333)	24,591	(88,670)
Cash flows provided by (used in) financing activities	(11,747)	(19,923)	13,350	5,565	(12,755)
Net increase (decrease) in cash and cash equivalents	10,702	0	(664)	0	10,038
Effect of exchange rate changes on cash and cash equivalents	(781)	0	465	0	(316)
Cash and cash equivalents at the beginning of the period	18,131	0	10,986	0	29,117
Cash and cash equivalents at the end of the period	28,052	0	10,787	0	38,839

CASH FLOW STATEMENT

At 31 December 2010 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by (used in) operating activities	21,623	67,543	29,763	(38,176)	80,753
Cash flows provided by (used in) investing activities	(4,371)	(32,268)	(42,462)	2,640	(76,461)
Cash flows provided by (used in) financing activities	(13,780)	(35,278)	12,611	35,536	(911)
Net increase (decrease) in cash and cash equivalents	3,472	(3)	(88)	0	3,381
Effect of exchange rate changes on cash and cash equivalents	199	0	251	0	450
Cash and cash equivalents at the beginning of the period	14,460	3	10,823	0	25,286
Cash and cash equivalents at the end of the period	18,131	0	10,986	0	29,117

CASH FLOW STATEMENT

At 31 December 2009 (in NOK million)	Statoil ASA	Statoil Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by (used in) operating activities	(3,547)	64,133	27,762	(15,296)	73,052
Cash flows provided by (used in) investing activities	21,639	(62,931)	(44,105)	10,302	(75,095)
Cash flows provided by (used in) financing activities	(8,809)	(1,199)	16,305	4,994	11,291
Net increase (decrease) in cash and cash equivalents	9,283	3	(38)	0	9,248
Effect of exchange rate changes on cash and cash equivalents	(1,095)	0	(1,756)	0	(2,851)
Cash and cash equivalents at the beginning of the period	6,272	0	12,617	0	18,889
Cash and cash equivalents at the end of the period	14,460	3	10,823	0	25,286

8.1.33 Supplementary oil and gas information (unaudited)

In accordance with Financial Accounting Standard 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 that was previously required by Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" (FAS 69). 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 judgment 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 judgement and key sources of estimation uncertainty - Proved oil and gas reserves.

No events have occurred since 31 December 2011 that would mean 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 experts 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 are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. At 31 December 2011, 10% of total proved reserves were related to such agreements (18% of oil and NGL and 5% of gas). This compares with 12% and 11% of total proved reserves for 2010 and 2009 respectively. Net entitlement oil and gas production from fields with such agreements was 75 million boe during 2011 (84 million boe for 2010 and 98 million boe for 2009). Statoil participates in such agreements in Algeria, Angola, Azerbaijan, Iran, Libya, Nigeria and Russia.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities under negotiated fiscal arrangements (PSAs) where the tax is paid on behalf of Statoil. Reserves are net of royalty oil paid in kind and quantities consumed during production.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on existing economical 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 2011 have been determined based on a 12-month average 2011 Brent blend price equivalent to USD 110.96/bbl. The increase in oil price from 2010, when the average Brent blend price was USD 79.02/bbl, has increased the profitable oil to be recovered from the accumulations, while Statoil's proved oil reserves under PSAs and similar contracts have as a result decreased. Gas reserves at year end 2011 has been determined based on achieved gas prices during 2011 giving a volume weighted average gas price of 2.1 NOK/Sm³. The comparable volume weighted average gas price used to determine gas reserves at year end 2010 was 1.7 NOK/Sm³, and the increase in gas price from 2010 to 2011 have affected the profitable gas reserves to be recovered accordingly. These changes are 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 deliver and sell 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 SDFI.

Statoil and 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 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 from properties in which it participates in the operations.

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 77% of total proved reserves at 31 December 2011 and no other country or continent 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.

Statoil announced during 2010 the establishment of joint ventures and the sales of a 40% interest in the Peregrino field in Brazil and a 40% interest in the oil sand leases in Alberta, Canada. These sales were approved and the effect on the 2011 proved reserves statement is a 66 million boe sale of reserves-in-place.

In 2011, Statoil has changed its accounting principle for interests in jointly controlled entities from equity accounting to proportional consolidation. As the change has been implemented with retrospective effect, comparable figures in this disclosure have been restated to reflect the new accounting principle. The restatement has not affected Statoil's total proved reserves in any of the periods presented, only the allocation between equity accounted investments and consolidated companies and only for 2010. For 2009, no proved reserves were held by jointly controlled entities. See note 3 *Accounting policy change for jointly controlled entities* for further information on the change in policy.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2008 to 2011, and the changes therein.

	Net proved oil and NGL reserves in million barrels				
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in consolidated companies					
At 31 December 2008	1,396	177	265	235	2,074
Revisions and improved recovery	195	(22)	64	6	243
Extensions and discoveries	39	6	44	45	134
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	(4)	-	-	(4)
Production	(279)	(19)	(63)	(15)	(376)
At 31 December 2009	1,351	138	310	272	2,070
Revisions and improved recovery	100	(7)	31	(2)	123
Extensions and discoveries	46	56	25	47	174
Purchase of reserves-in-place	-	-	-	4	4
Sales of reserves-in-place	-	-	-	-	-
Production	(256)	(18)	(53)	(21)	(348)
At 31 December 2010	1,241	170	313	299	2,023
Revisions and improved recovery	295	(42)	46	11	310
Extensions and discoveries	71	-	-	60	132
Purchase of reserves-in-place	14	-	-	106	120
Sales of reserves-in-place	-	-	-	(66)	(66)
Production	(252)	(15)	(46)	(26)	(338)
At 31 December 2011	1,369	114	313	385	2,181

	Net proved oil and NGL reserves in million barrels				
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	127	127
Revisions and improved recovery	-	-	-	(18)	(18)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2009	-	-	-	105	105
Revisions and improved recovery	-	-	-	1	1
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2010	-	-	-	101	101
Revisions and improved recovery	-	-	-	(1)	(1)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2011	-	-	-	95	95
Total Proved Oil and NGL Reserves including reserves in equity accounted investments at 31 December 2009	1,351	138	310	376	2,174
Total Proved Oil and NGL Reserves including reserves in equity accounted investments at 31 December 2010	1,241	170	313	400	2,124
Total Proved Oil and NGL Reserves including reserves in equity accounted investments at 31 December 2011	1,369	114	313	480	2,276

Statoil's proved reserves of bitumen in Americas, representing less than 4% of our proved reserves, is included as oil in the table above.

	Net proved gas reserves in billion standard cubic feet				
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in consolidated companies					
At 31 December 2008	17,581	827	481	95	18,984
Revisions and improved recovery	690	(31)	(89)	(9)	561
Extensions and discoveries	35	-	-	87	122
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	(1,367)	(49)	(54)	(48)	(1,519)
At 31 December 2009	16,938	747	338	125	18,148
Revisions and improved recovery	394	(62)	(4)	4	332
Extensions and discoveries	381	-	227	340	948
Purchase of reserves-in-place	-	-	-	45	45
Sales of reserves-in-place	-	-	-	-	-
Production	(1,370)	(51)	(41)	(47)	(1,509)
At 31 December 2010	16,343	634	521	466	17,965
Revisions and improved recovery	383	22	(50)	4	359
Extensions and discoveries	111	-	-	451	563
Purchase of reserves-in-place	138	-	-	90	227
Sales of reserves-in-place	-	-	-	-	-
Production	(1,287)	(48)	(40)	(59)	(1,434)
At 31 December 2011	15,689	608	431	952	17,681

	Net proved gas reserves in billion standard cubic feet				
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	-	-
Revisions and improved recovery	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	-	-
At 31 December 2009	-	-	-	-	-
Revisions and improved recovery	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	-	-
At 31 December 2010	-	-	-	-	-
Revisions and improved recovery	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	-	-
At 31 December 2011	-	-	-	-	-
Total Proved Gas Reserves including reserves in equity accounted investments at 31 December 2009	16,938	747	338	125	18,148
Total Proved Gas Reserves including reserves in equity accounted investments at 31 December 2010	16,343	634	521	466	17,965
Total Proved Gas Reserves including reserves in equity accounted investments at 31 December 2011	15,689	608	431	952	17,681

Net proved oil, NGL and gas reserves in million barrels oil equivalent					
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in consolidated companies					
At 31 December 2008	4,529	324	351	252	5,456
Revisions and improved recovery	318	(28)	48	5	343
Extensions and discoveries	45	6	44	60	155
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	(4)	-	-	(4)
Production	(523)	(28)	(73)	(24)	(647)
At 31 December 2009	4,369	271	370	294	5,304
Revisions and improved recovery	170	(18)	30	(1)	182
Extensions and discoveries	114	56	65	108	343
Purchase of reserves-in-place	-	-	-	12	12
Sales of reserves-in-place	-	-	-	-	-
Production	(500)	(27)	(60)	(29)	(617)
At 31 December 2010	4,153	283	406	382	5,224
Revisions and improved recovery	364	(38)	37	12	374
Extensions and discoveries	91			141	232
Purchase of reserves-in-place	38			122	161
Sales of reserves-in-place				(66)	(66)
Production	(481)	(23)	(53)	(36)	(593)
At 31 December 2011	4,165	222	390	555	5,331

	Net proved oil, NGL and gas reserves in million barrels oil equivalent				
	Norway	Eurasia excluding Norway	Africa	Americas	Total
Reserves in equity accounted investments					
At 31 December 2008	-	-	-	127	127
Revisions and improved recovery	-	-	-	(18)	(18)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2009	-	-	-	105	105
Revisions and improved recovery	-	-	-	1	1
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2010	-	-	-	101	101
Revisions and improved recovery	-	-	-	(1)	(1)
Extensions and discoveries	-	-	-	-	-
Purchase of reserves-in-place	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-
Production	-	-	-	(5)	(5)
At 31 December 2011	-	-	-	95	95
Total Proved Reserves including reserves in equity accounted investments at 31 December 2009	4,369	271	370	398	5,408
Total Proved Reserves including reserves in equity accounted investments at 31 December 2010	4,153	283	406	483	5,325
Total Proved Reserves including reserves in equity accounted investments at 31 December 2011	4,165	222	390	650	5,426

Statoil's proved reserves of bitumen in Americas, representing less than 4% of our proved reserves, is included as oil in the table above.

Reserves in consolidated companies	Norway	Eurasia excluding Norway	Africa	Americas	Total
Net proved oil and NGL reserves in million barrels					
At 31 December 2008					
Developed	1,113	108	232	41	1,494
Undeveloped	283	69	33	195	580
At 31 December 2009					
Developed	1,028	94	208	83	1,413
Undeveloped	322	44	102	189	656
At 31 December 2010					
Developed	950	99	192	82	1,322
Undeveloped	291	71	121	218	701
At 31 December 2011					
Developed	919	102	219	103	1,344
Undeveloped	450	11	93	282	837
Net proved gas reserves in billion standard cubic feet					
At 31 December 2008					
Developed	14,482	357	296	74	15,209
Undeveloped	3,099	470	185	21	3,775
At 31 December 2009					
Developed	14,138	523	256	73	14,990
Undeveloped	2,800	224	83	51	3,158
At 31 December 2010					
Developed	13,722	421	221	336	14,700
Undeveloped	2,621	214	300	130	3,265
At 31 December 2011					
Developed	12,661	371	293	404	13,730
Undeveloped	3,027	237	138	548	3,951
Net proved oil, NGL and gas reserves in million barrels oil equivalent					
At 31 December 2008					
Developed	3,693	172	285	54	4,204
Undeveloped	836	152	66	198	1,253
At 31 December 2009					
Developed	3,548	187	254	96	4,084
Undeveloped	821	84	116	198	1,219
At 31 December 2010					
Developed	3,395	174	231	142	3,941
Undeveloped	758	109	175	241	1,283
At 31 December 2011					
Developed	3,175	168	272	175	3,790
Undeveloped	990	54	118	380	1,541

Reserves in equity accounted investments	Norway	Eurasia excluding Norway	Africa	Americas	Total
Net proved oil, NGL and gas reserves in million barrels oil equivalent					
At 31 December 2008					
Developed				25	25
Undeveloped				102	102
At 31 December 2009					
Developed				28	28
Undeveloped				76	76
At 31 December 2010					
Developed				35	35
Undeveloped				66	66
At 31 December 2011					
Developed				37	37
Undeveloped				58	58

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 million)	2011	At 31 December 2010	2009
Unproved Properties	79,860	38,283	49,497
Proved Properties, wells, plants and other equipment	827,521	704,311	655,886
Total Capitalised cost	907,381	742,594	705,383
Accumulated depreciation, impairment and amortisation	(466,330)	(419,919)	(379,575)
Net Capitalised cost	441,051	322,675	325,808

Net capitalised cost related to equity accounted investments as of 31 December 2011 was NOK 3.7 billion, NOK 3.8 billion in 2010 and NOK 3.7 billion in 2009.

In addition capitalised cost related to Oil and Gas production activities classified as held for sale amounted to NOK 44.9 billion as of 31 December 2010. As per 31 December 2011 and 2009, 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 million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year ended 31 December 2011					
Exploration expenditures	6,562	2,481	1,709	8,002	18,754
Development costs	36,857	2,832	11,098	19,439	70,226
Acquired proved properties	1,731	0	0	7,563	9,294
Acquired unproved properties	84	289	5,135	26,185	31,693
Total	45,234	5,602	17,942	61,189	129,967
Year ended 31 December 2010					
Exploration expenditures	5,974	1,647	1,987	7,195	16,803
Development costs	29,284	2,531	11,262	10,439	53,516
Acquired proved properties	0	0	0	587	587
Acquired unproved properties	31	1,046	0	9,313	10,390
Total	35,289	5,224	13,249	27,534	81,296
Year ended 31 December 2009					
Exploration expenditures	8,170	1,310	2,465	4,950	16,895
Development costs	30,704	3,611	10,627	11,958	56,900
Acquired unproved properties	0	0	12	1,313	1,325
Total	38,874	4,921	13,104	18,221	75,120

Expenditures incurred in Oil and Gas Development Activities related to equity accounted investments in 2011 were NOK 266 million, NOK 316 million in 2010 and NOK 286 million in 2009.

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.

Activities included in the development and production segments as presented in Statoil's segment disclosures in note 4 *Segments* to the financial statements, but excluded from the table below relates to commodity based derivatives, transportation, 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 in addition to uplift and tax credits only. No deductions are made for interest or other elements not included in the table below.

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year ended 31 December 2011					
Sales	489	5,109	4,878	985	11,461
Transfers	203,635	6,131	23,066	15,612	248,444
Total revenues	204,124	11,240	27,944	16,597	259,905
Exploration expenses	(5,119)	(2,508)	(2,015)	(4,196)	(13,838)
Production costs	(20,634)	(1,702)	(3,149)	(5,167)	(30,652)
Depreciation, amortisation and net impairment losses	(29,577)	(2,788)	(6,528)	(4,504)	(43,397)
Total costs	(55,330)	(6,998)	(11,692)	(13,867)	(87,887)
Results of operations before tax	148,794	4,242	16,252	2,730	172,018
Tax expense	(109,678)	(3,227)	(9,477)	2,244	(120,138)
Result of operations	39,116	1,015	6,775	4,974	51,880
Year ended 31 December 2010					
Sales	1	2,706	2,526	733	5,966
Transfers	166,219	6,871	24,232	10,656	207,978
Total revenues	166,220	9,577	26,758	11,389	213,944
Exploration expenses	(5,497)	(1,448)	(2,033)	(6,795)	(15,773)
Production costs	(21,372)	(1,297)	(3,165)	(4,076)	(29,910)
Depreciation, amortisation and net impairment losses	(25,731)	(4,099)	(7,503)	(5,034)	(42,367)
Total costs	(52,600)	(6,844)	(12,701)	(15,905)	(88,050)
Results of operations before tax	113,620	2,733	14,057	(4,516)	125,894
Tax expense	(82,226)	(755)	(6,868)	964	(88,885)
Result of operations	31,394	1,978	7,189	(3,552)	37,009

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year ended 31 December 2009					
Sales	5	2,968	7,950	689	11,612
Transfers	154,440	5,320	16,877	6,085	182,722
Total revenues	154,445	8,288	24,827	6,774	194,334
Exploration expenses	(5,187)	(1,047)	(2,238)	(8,218)	(16,690)
Production costs	(19,395)	(1,440)	(3,432)	(1,768)	(26,035)
Depreciation, amortisation and net impairment losses	(25,566)	(2,464)	(9,721)	(4,902)	(42,653)
Total costs	(50,148)	(4,951)	(15,391)	(14,888)	(85,378)
Results of operations before tax	104,297	3,337	9,436	(8,114)	108,956
Tax expense	(75,690)	(102)	(3,182)	1,684	(77,290)
Result of operations	28,607	3,235	6,254	(6,430)	31,666

The results of operations for oil and gas producing activities within equity accounted investments located outside of Norway amounts to NOK 422 million, NOK 109 million and NOK 26 million for the years ended 31 December 2011, 2010 and 2009, respectively.

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 contractual arrangements in existence 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 million)	Norway	Eurasia excluding Norway	Africa	Americas	Total
At 31 December 2011					
Consolidated companies					
Future net cash inflows	1,781,649	102,758	226,893	245,643	2,356,943
Future development costs	(156,460)	(17,049)	(23,319)	(39,201)	(236,029)
Future production costs	(484,587)	(23,804)	(51,255)	(84,353)	(643,999)
Future income tax expenses	(851,809)	(18,162)	(51,752)	(36,831)	(958,554)
Future net cash flows	288,793	43,743	100,567	85,258	518,361
10 % annual discount for estimated timing of cash flows	(120,022)	(19,538)	(38,565)	(38,140)	(216,265)
Standardised measure of discounted future net cash flows	168,771	24,205	62,002	47,118	302,096
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	2,462	2,462
Total standardised measure of discounted future net cash flows including equity accounted investments	168,771	24,205	62,002	49,580	304,558
At 31 December 2010					
Consolidated companies					
Future net cash inflows	1,353,424	99,326	163,551	144,976	1,761,277
Future development costs	(139,961)	(23,457)	(29,041)	(18,582)	(211,041)
Future production costs	(440,344)	(30,608)	(51,363)	(62,336)	(584,651)
Future income tax expenses	(567,513)	(6,773)	(30,296)	(17,484)	(622,066)
Future net cash flows	205,606	38,488	52,851	46,574	343,519
10 % annual discount for estimated timing of cash flows	(86,668)	(16,096)	(21,596)	(16,739)	(141,099)
Standardised measure of discounted future net cash flows	118,938	22,392	31,255	29,835	202,420
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	3,736	3,736
Total standardised measure of discounted future net cash flows including equity accounted investments	118,938	22,392	31,255	33,571	206,156
At 31 December 2009					
Consolidated companies					
Future net cash inflows	1,387,084	66,055	113,642	90,548	1,657,329
Future development costs	(118,505)	(12,362)	(22,047)	(12,095)	(165,009)
Future production costs	(437,396)	(22,806)	(33,665)	(42,932)	(536,799)
Future income tax expenses	(624,221)	(3,033)	(21,199)	(7,642)	(656,095)
Future net cash flows	206,962	27,854	36,731	27,879	299,426
10 % annual discount for estimated timing of cash flows	(94,462)	(11,806)	(11,479)	(7,537)	(125,284)
Standardised measure of discounted future net cash flows	112,500	16,048	25,252	20,342	174,142
Equity accounted investments					
Standardised measure of discounted future net cash flows	-	-	-	2,097	2,097
Total standardised measure of discounted future net cash flows including equity accounted investments	112,500	16,048	25,252	22,439	176,239

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK million)	2011	2010	2009
Consolidated companies			
Standardised measure at beginning of year	202,420	174,142	183,591
Net change in sales and transfer prices and in production (lifting) costs related to future production	500,602	130,402	(288,973)
Changes in estimated future development costs	(64,255)	(53,071)	(48,980)
Sales and transfers of oil and gas produced during the period, net of production cost	(243,004)	(194,931)	(179,072)
Net change due to extensions, discoveries, and improved recovery	53,291	11,447	9,403
Net change due to purchases and sales of minerals in place	13,851	(448)	(530)
Net change due to revisions in quantity estimates	181,284	47,285	101,298
Previously estimated development costs incurred during the period	69,571	54,108	56,900
Accretion of discount	(216,350)	32,859	214,065
Net change in income taxes	(195,314)	627	126,440
Total change in the standardised measure during the year	99,676	28,278	(9,449)
Standardised measure at end of year	302,096	202,420	174,142
Equity accounted investments			
Standardised measure at end of year	2,462	3,736	2,097
Standardised measure at end of year including equity accounted investments	304,558	206,156	176,239

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

The Board of Directors and Shareholders of Statoil ASA

We have audited the accompanying consolidated balance sheets of Statoil ASA as of 31 December 2011, 2010 and 2009, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended 31 December 2011. 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA at 31 December 2011, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three 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 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 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated 13 March 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young AS

Stavanger, Norway
13 March 2012

8.2.2 Report of Ernst & Young AS on Statoil's internal control over financial reporting

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Statoil ASA

We have audited Statoil ASA's internal control over financial reporting as of 31 December 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). 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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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 2011, based on the COSO criteria.

As indicated in the accompanying management's report on internal control over financial reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Brigham Exploration Company, which is included in the 2011 consolidated financial statements of Statoil ASA and constituted NOK 42 676 million and NOK 13 276 million of total assets and total liabilities respectively as of 31 December 2011, and NOK 465 million and NOK 35 million of total revenues and other income, and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Statoil ASA also did not include an evaluation of the internal control over financial reporting of Brigham Exploration Company.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Statoil ASA as of 31 December 2011, 2010 and 2009 and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended 31 December 2011 of Statoil ASA and our report dated 13 March 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young AS

Stavanger, Norway
13 March 2012

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
- CO₂ - 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
- OTC - Over-the-counter
- OTS - Oil trading and supply department
- PBO - Project benefit obligation
- PDO - Plan for development and operation
- PRO - Projects business cluster
- 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 and product development
- TSP - Technical service provider
- USD - United States dollar

Metric abbreviations etc:

- bbl - barrel
- mbbbl - 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.
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material.
- BOE (barrels of oil equivalent): A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content.
- Carbon footprint: Total set of greenhouse gas emissions caused directly and indirectly by an individual, organisation, event or product.
- Clastic reservoir systems: The integrated static and dynamic characteristics of a hydrocarbon reservoir formed by clastic rocks of a specific depositional sedimentary succession and its seal.
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields.
- Downstream: The selling and distribution of products derived from upstream activities.
- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a production sharing agreement (PSA) that correspond to Statoil's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent Statoil's share of the volumes

distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years.

- FCC (fluid catalytic cracking): A process used to convert the high-boiling hydrocarbon fractions of petroleum crude oils to more valuable gasoline, gases and other products.
- GTL (gas to liquids): The technology used for chemical conversion of natural gas into transportable liquids (diesel and naphtha) and specialty products (base oils).
- Heavy oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, 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 (increased 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 "Operational review". 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" 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; 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 divestment in Gassled, the Pazflor development in Angola, the opening of the Vega field in the North Sea and the Tyrihans subsea field in the Norwegian Sea, our interests in the Marcellus and Eagle Ford shale gas developments in the U.S., and the Peregrino field in Brazil, the Brigham acquisition and the Johan Sverdrup (formerly Aldous and Avaldsnes) and Skrugard discoveries; 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; 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; new 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; impact of PSA effects; projected impact or timing of administrative or governmental rules, standards, decisions, standards or laws (including taxation laws); 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; the sovereign debt situation in Europe; global political events and actions, including war, terrorism and sanctions; security breaches; 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; 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: 23 March 2012

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 3.7 "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 Ernst & Young AS.
Exhibit 15(a)(ii)	Consent of DeGolyer and MacNaughton.
Exhibit 15(a)(iii)	Report of DeGolyer and MacNaughton.
Exhibit 15(a)(iv)	Consent of Cawley, Gillespie & Associates, Inc.
Exhibit 15(a)(v)	Report of Cawley, Gillespie & Associates, Inc.

* Furnished only

The total amount of long-term debt securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of Statoil ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

13 Cross reference to Form 20-F

		Sections
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Item 2.	Offer Statistics and Expected Timetable	N/A
Item 3.	Key Information	
	A. Selected Financial Data	1.1; 1.3; 4.1.2; 6; 6.1.1; 6.7
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	C. Reasons for the Offer and Use of Proceeds	N/A
	D. Risk Factors	5.1
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	B. Business Overview	2; 3; 4.1.1; 4.1.3; 4.1.4
	C. Organizational Structure	2.1; 2.4; 3.7
	D. Property, Plants and Equipment	3.1 - 3.4; 3.9; 3.12; 4.2.5; 8.1.34
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Item 7.	Major Shareholders and Related Party Transactions	
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	C. Interests of Experts and Counsel	N/A
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	F. Expenses of the Issue	N/A
Item 10.	Additional Information	
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	B. Memorandum and Articles of Association	6.1; 6.8; 7.1; 7.3; 7.10; 8.1.21
	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	1.2
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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
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Item 13.	Defaults, Dividend Arrearages and Delinquencies	None
Item 14.	Material Modifications to the Rights of Security Holders and Use of Proceeds	None
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