2011/ STATUTORY REPORT

Statoil

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Statutory report 2011

Board of directors report

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. The reserve replacement ratio (RRR) was 1.17 in 2011.

Net operating income was NOK 211.8 billion in 2011, up by 54% compared with NOK 137.3 billion in 2010. In 2011, net operating income was positively impacted by higher prices, and gains on sale of assets and unrealised gains on derivatives. Lower volumes of both liquids and gas sold and increased operating expenses partly offset the increase in net operating income.

Total equity production was 1,850 mboe per day in 2011, compared to 1,888 mboe per day in 2010.

Cash flows from operations, combined with proceeds from our continued portfolio optimisation, have been strong in 2011.

Statoil's safety results with respect to serious incidents have been improved over the recent years. The overall Serious Incident Frequency (SIF) improved from 1.4 in 2010 to 1.1 in 2011. Excluding the reporting segment Fuel & Retail (SFR), the SIF was 0.9 in 2011, compared to 1.3 in 2010.

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 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 delivered strong exploration results in 2011, adding more than 1 billion barrels to the resource base. The reserve replacement ratio (RRR) was 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.

Expectations for 2012

For 2012, equity production 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.

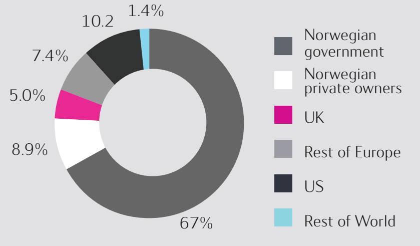
Organic capital expenditures (i.e. excluding acquisitions and capital leases), are estimated to be around USD 17 billion in 2012, including expenditures relating to our new assets from the recent Brigham acquisition.

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 at around USD 3 billion, excluding signature bonuses.

The Statoil share

The board of directors proposes 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.

Distribution of shareholders



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

In 2010, the ordinary dividend was NOK 6.25 per share, an aggregate total of NOK 19.9 billion.

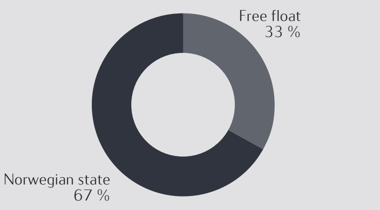
The Statoil share price is showing a upward trend during 2011, starting out 3 January 2011 at NOK 140.30, ending up at NOK 153.50 at the end of 2011.

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 is the leading operator on the NCS. The company has business operations in 41 countries and territories.

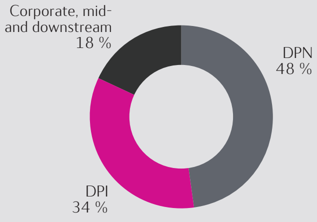
Statoil ASA is a public limited company organised under the laws of Norway. The largest offices are in Stavanger, Bergen and Oslo, and the group had approximately 31,700 permanent employees as of 31 December 2011. Of this total, approximately 10,400 were employees of the Statoil Fuel & Retail ASA group, in which we held a 54% majority ownership interest as of 31 December 2011.

Ownership structure*



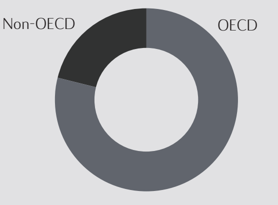
*as of 31 December 2011

Non-current assets*

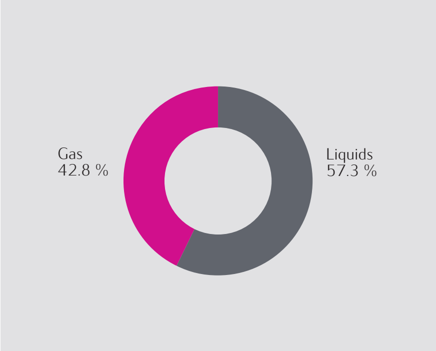


*as of 31 December 2011

Total assets



Entitlement production of liquids and gas



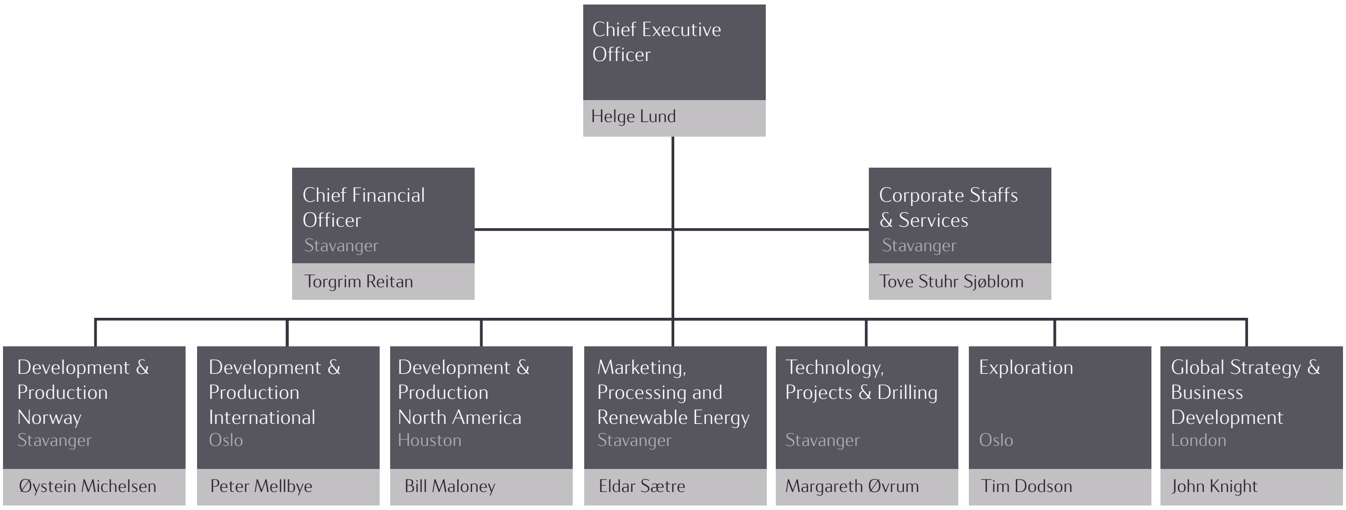
The combined exploration and production business had an average equity liquids and natural gas production of 1,850 mmboe per day in 2011. Proved reserves at the end of 2011 were 2,276 mmboe of oil and 3,150 mmboe of natural gas, corresponding to aggregate proved reserves of 5,426 mmboe.

Statoil 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. The company has also substantial processing and refining operations, and is contributing to the development of new energy resources, have ongoing activities in the areas of offshore wind and biofuels, and is at the forefront of the implementation of technology for carbon capture and storage (CCS).

In further developing our business, Statoil aims to grow and enhance our portfolio over the coming years 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.

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.

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



Statoil reports its business in five reporting segments that are based on the new corporate structure: Development and Production Norway (DPN), Development and Production International (DPI), which combines the D&PI 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, CFO and Corporate Staff and Services.

Development and Production Norway (DPN)

DPN comprises the upstream activities on the Norwegian continental shelf (NCS). DPN has ownership interests in exploration acreage and developed fields on the NCS, and participates in 227 licences, of which 171 are operatorships. DPN is the operator of 44 developed fields on the NCS. Total production amounted to 1.316 mmboe per day in 2011, representing 71% of Statoil's equity production.

Development and Production International (DPI)

DPI comprises the upstream activities in both the North America and the worldwide upstream activities that are outside the NCS. Total production amounted to 534 mboe per day in 2011, representing 29% of Statoil's equity production.

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.

Exploration (EXP)
EXP is an integrated business area responsible for creating a global centre for exploration and deploying resources to priority activities across the portfolio. Main focus areas are accessing high potential new acreage in priority basins, globally prioritising and drilling more high impact wells in growth and frontier basins, delivering near field exploration on the Norwegian continental shelf and other select areas, and achieving step change improvements in performance.

Technology, Projects and Drilling (TPD)
TPD's main focus areas is to provide safe, efficient and cost-competitive global well, 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.

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

Fuel & Retail (SFR)
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 seperate 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 also markets refined products directly to consumer and industrial markets.

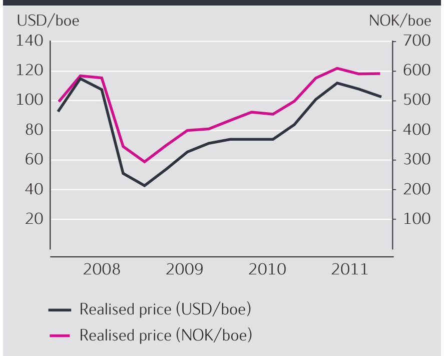
Group profit and loss analysis

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)	For the year ended 31 December 2011	2010 (restated)	11-10 change
Revenues and other income			
Revenues	645.6	527.0	23%
Net income from associated companies	1.3	1.2	8%
Other income	23.3	1.8	>100%
Total revenues and other income	670.2	529.9	26%
Operating expenses			
Purchase [net of inventory variation]	319.6	257.4	24%
Operating expenses and Selling, general and administrative expenses	73.6	68.8	7%
Depreciation, amortisation and net impairment losses	51.4	50.7	1%
Exploration expenses	13.8	15.8	(12%)
Total operating expenses	(458.4)	(392.7)	17%
Net operating income	211.8	137.3	54%
Net financial items	2.1	(0.4)	>100 %
Income before tax	213.8	136.8	56%
Income tax	(135.4)	(99.2)	37%
Net income	78.4	37.6	>100%
Earnings per share for income attributable to equity holders of company diluted	24.8	11.9	>100%

Total revenues and other income amounted to NOK 670.2 billion in 2011 compared to NOK 529.9 billion in 2010. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil. In addition, we also market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as purchases net of inventory variations and sales, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net.

Group realised oil prices



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.

Total liquids liftings were 910 mboe per day in 2011, a decrease of 6% compared to 2010 when total liquids liftings were 969 mboe per day. Total liftings of gas were down 4% from 738 mboe per day in 2010 to 706 mboe per day in 2011.

Net income from associated companies was NOK 1.3 billion in 2011, compared to NOK 1.2 billion in 2010. With effect from 2011, Statoil changed the policy for accounting for jointly controlled entities, from application of the equity method to proportionate consolidation. Proportionate consolidation has been retrospectively applied in the Consolidated financial statement.

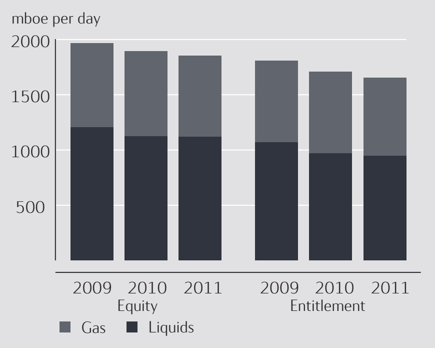
Other income was NOK 23.3 billion in 2011, compared to NOK 1.8 billion in 2010. The significant increase in other income from 2010 to 2011 stems mainly from gains on sale of assets primarily related to the reduction of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled in 2011.

Purchase [net of inventory variation] includes the cost of the liquids production purchased from the Norwegian State pursuant to the Owners Instruction. The purchase [net of inventory variation] amounted to NOK 319.6 billion in 2011, compared to NOK 257.4 billion in 2010. The 24% increase from 2010 to 2011 was 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 compare to 2010 when operating expenses and selling, general and administrative expenses were NOK 68.8 billion. The 7% increase reflects mainly the higher activity level in 2011 related to start-up and ramp-up of production on various fields, increased transportation and processing costs, and increased ownership shares. Also, changes in removal estimates, higher tariffs and royalties paid and increased business development costs added to the increase in expenses.

Total equity liquids and gas production decreased from 1.888 mmboe per day in 2010 to 1.850 mmboe per day in 2011. 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.

Entitlement and equity production



Total entitlement liquids and gas production decreased from 1.705 mmboe per day in 2010 to 1.650 mmboe per day in 2011. Total entitlement production decreased by 6% from 2010 to 2011 and was impacted by the reduction in equity production and by increasing production-sharing agreement (PSA) effects.

The production cost per boe based on equity volumes for the 12 months ending 31 December 2011 and 2010 was NOK 43.1 and NOK 38.6, respectively. Adjusted for restructuring costs, reversal of restructuring costs and other costs arising from the Hydro-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.

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. Included in these totals were net impairment losses of NOK 2.0 billion for 2011 and NOK 4.8 billion for 2010. 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.

Depreciation, amortisation and net impairment losses (in NOK billion)	2011	Year ended 31 December 2010 (restated)	change
Ordinary depreciation	50.1	45.7	10 %
Amortisation of intangible assets	0.1	0.2	(44 %)
Impairments	4.5	4.7	(5 %)
Reversal of impairments	(3.3)	0.1	>(100 %)
Impairment of intangible assets	0.0	0.0	0 %
Depreciation, amortisation and net impairment losses	51.4	50.7	1 %

Exploration expenditures are capitalised to the extent that exploration efforts are considered successful, or pending such assessment. Otherwise, such expenditures are expensed.

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 decreased 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.

Exploration Expenses (in NOK billion)	For the year ended 31 December 2011	2010 (restated)	change
Exploration expenditure (activity)	18.8	16.8	12 %
Expensed, previously capitalised exploration expenditure	1.8	2.6	(30 %)
Capitalised share of current periods exploration activity	(6.4)	(3.9)	64 %
Impairment	1.6	1.9	(19 %)
Reversal of impairment	(1.9)	(1.6)	14 %
Exploration Expenses	13.8	15.8	(12 %)

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.

Net operating income was NOK 211.8 billion in 2011, compared with NOK 137.3 billion in 2010. 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.

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 Teminal 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.

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.

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%. 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.

In 2011, the **non-controlling interest** in net profit was NOK 0.3 billion, compared to NOK 0.4 billion in 2010. 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. 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.

Considering the **proposed dividend** for 2011, the remaining net income in the parent company will be allocated to reserve for valuation variances and retained earnings with NOK 17.3 billion and NOK 30.3 billion, respectively. The company's distributable equity after allocations amounts to NOK 132.5 billion.

In accordance with Section 3-3 of the Norwegian Accounting Act, the board of directors confirms that the financial statements have been prepared on the basis of the **going concern** assumption.

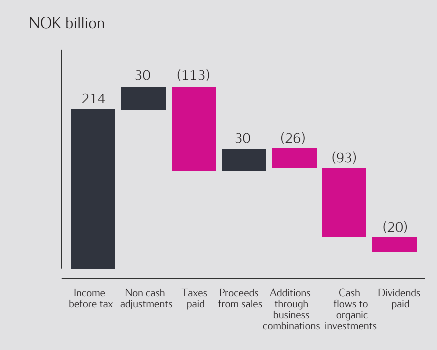
Cash flows

Statoil delivered strong cash flows in 2011, mainly as a result of increased cash flows provided by operations and continued portfolio optimisation.

For **cash flows from operations,** the major factors impacting changes between periods are our level of profitability and taxes paid. In 2011, income before tax was NOK 213.8 billion, an increase of NOK 77 billion compared to NOK 136.8 billion in 2010, mainly caused by higher liquids and gas prices in 2011 compared to 2010. In 2011, taxes paid was NOK 112.6 billion, an increase of NOK 20.3 billion compared to 2010.

Cash flows used in investing activities are impacted by organic investments, additions through business combinations and proceeds from sales of assets. Cash flows to organic investments were NOK 92.8 billion in 2011 compared to 78.4 billion in 2010, mainly driven by the increased investment activity level. 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 increase in cash spent on investing activities was partly offset by proceeds from sales of 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.

Sources and use of cash flows



The major factors impacting **cash flows provided by (used in) financing activities** are changes in long-term and short-term borrowing and dividend paid. 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. In 2011, cash flows used in financing activities 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.

Liquidity and capital resources

Statoil has maintained a strong financial position throughout the year and the net debt to capital employed ratio was 19.9% at 31 December 2011.

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. However, our cash flows from operations are 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.

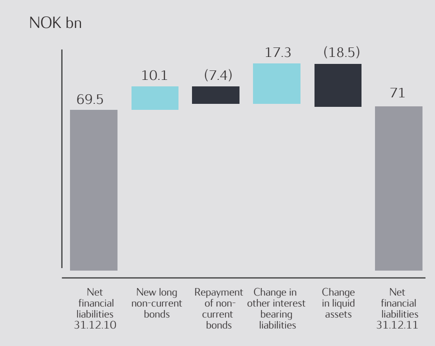
The USD 3 billion multi-currency revolving credit facility that Statoil ASA, guaranteed by Statoil Petroleum AS, has available from a group of 20 international banks, had its term extended by one year until December 2016. Through one more extension option the facility may be further extended to December 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.

Statoil's 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.

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.

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.

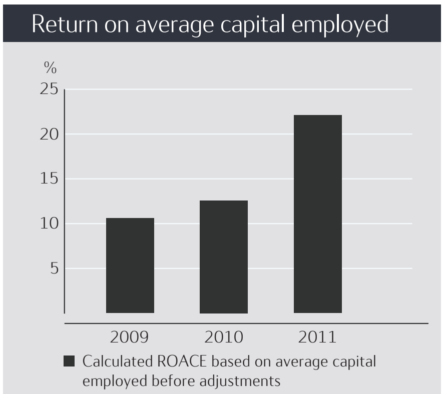
The net debt to capital employed ratio before adjustments, defined as net interest-bearing financial liabilities before adjustments in relation to capital employed before adjustments, was 19.9% in 2011, compared with 23.5% in 2010.The net debt to capital employed ratio adjusted was 21.1% at 31 December 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.

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. The company's 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.

Return on average capital employed

Statoil achieved a competitive rate of return on the capital employed in 2011.



We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. ROACE is defined as a non-GAAP financial measure.

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.

Financial risks

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

The factors that influence the results of our operations include: the level of crude oil and natural gas prices, trends in the exchange rate between the USD, in which the trading price of crude oil is generally stated 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 Organisation 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 the existing market structures and to the overall level and volatility of prices.

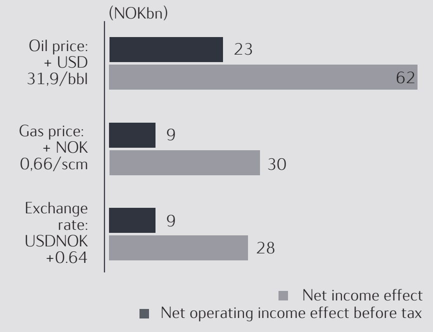
The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas average sales prices, reference refining margins and the NOK/USD exchange rates for 2011, 2010 and 2009.

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
USDNOK 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 impact the financial results in 2012.

Indicative effects on 2012 results



The estimated sensitivity of our financial results to each of the factors has been estimated based on the assumption that all other factors would 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 US dollars (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.

Health, safety and the environment

Statoil's ambition is to operate with zero harm to people and the environment and in accordance with principles for sustainable development. Safe and efficient operations are our first priority.

Statoil has committed itself to ensuring safe operations that protect people, the environment, communities and material assets, and to using natural resources efficiently and providing energy that supports sustainable development.

The board of directors emphasises the importance of understanding factors that create risks in order to avoid major accidents. We work systematically to mitigate risks that are critical to operating safely and reliably, and continuous improvement for better safety results has high attention in all our business areas. In 2010 the board established the health, safety, environment and ethics sub-committee to strengthen the board's focus on HSE and ethics.

In order to meet our goal of improving safety results in all our businesses, Statoil holds numerous training sessions in compliance, leadership and risk management. The compliance programme focuses on the integration of our values in all activities, and on compliance with internal and external requirements. We are confident in these focus areas, but will strive hard to improve them in the years ahead.

We have identified the following four priority areas as drivers of improvements. They were carried forward from 2009 and will be further carried forward into 2012. We consider them to be fundamental to our ability to deliver on our policy commitments and our ambition to be an industry leader in HSE:

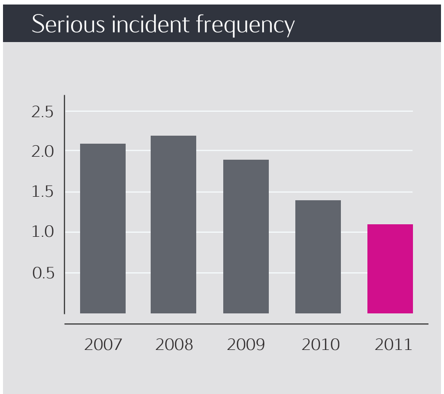
- Committed leadership and compliance
- Understanding and managing our risks
- Simplification and harmonisation of our procedures and work processes
- Increased focus on technical integrity and barriers

The industry in general, including Statoil, is determined to learn from incidents and accidents to prevent similar occurrences in the future. The use of risk management and compliance measures is important, and compensatory measures are continuously implemented in order to reduce the risk of accidents.

Our ambition is to be an industry leader in HSE. Effective leadership includes achieving results and setting good examples. Our aspirations are to:

- produce the best HSE results in the industry in which we participate
- continuously improve our HSE performance and be a driving force for raising HSE standards in the industry
- implement technology and solutions that balance tailor-made solutions with driving overall technological change
- proactively develop and apply appropriate technology and processes to attain operational excellence and sustainable conduct
- maintain industry and stakeholder recognition for sound HSE performance
- be a positive example to others and to attract employees and partners

Statoil's safety results with respect to serious incidents have been improved over the recent years. The overall Serious incident frequency (SIF) improved from 1.4 in 2010 to 1.1 in 2011. Excluding the reporting segment Fuel & Retail (SFR), the SIF was 0.9 in 2011, compared to 1.3 in 2010.



There was one fatality in 2011. A contractor employee, performing maintenance work at service stations in Riga (Latvia) was killed in a traffic accident. In addition, on 6 October, a contractor employee was reported missing on the Visund platform in the North Sea. An extensive search operation, both at the platform, in the sea and on the seabed around the platform was unfortunately unsuccessful.

Statoil strives to ensure a working environment that promotes job satisfaction and good health. We emphasise the psychosocial aspects of the working environment and promote the good health and well-being of all our employees. We make systematic efforts to design and improve the working environment in order to prevent occupational accidents, work-related diseases and sickness absence. Five strategic areas for risk assessment have been identified: chemical exposure, workload, noise, ergonomics and health promotion.

This work involves monitoring of physical, chemical and organisational factors in the working environment, and a system for following up on groups or individuals that are exposed to risks in their working environment. Special attention is devoted to chemical health hazard.

The sick leave rate in Statoil increased from 3.6% in 2010 to 3.8% in 2011, and the increase is most significant in our Norwegian operations. The sickness absence is followed closely by managers at all levels.

In November 2011, Statoil accepted NOK 1.05 million in penalties for contravention of the terms or conditions of its license from Alberta Environment to use surface water utilized to freeze ice roads for transportation of equipment. Surface water is not used in Statoil's oil sands production process. The penalty consisted of a CAN 5,000 fine and a creative sentencing order in the amount of CAN 185,000 to be put towards the creation of an online training portal to communicate best practices for surface water diversion to the oil and gas industry in Alberta. Statoil had been underestimating water withdrawal from an approved location, by withdrawing water from two waterholes not included in the license, by using an intake screen with a larger opening than authorised, and by not properly measuring water diversion according to the requirements in the license. There was no pollution associated with Statoil's water use or breach of its license.

In 2011, Statoil accepted NOK 3.0 million in penalties for not ensuring that a contractor, working for Statoil on the Troll A platform, had the neccessary HSE systems and procedures in place. Statoil failed to identify and mitigate the gap between Statoil's own HSE systems and the HSE systems of the contractor. Operations performed by the contractor on the platform were not in accordance with Statoil's HSE systems and a person was injured when performing work on the platform.

People and the organisation

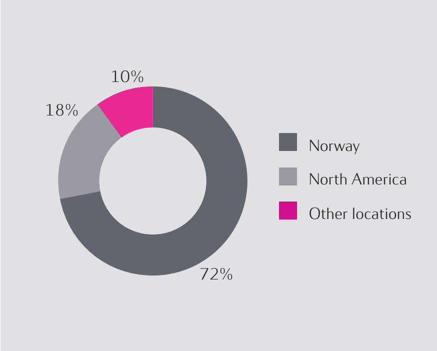
Statoil will create value for the owners based on a clear performance framework defined by our corporate values and principles.

Statoil's ambition is to be a globally competitive company. It is a key priority to create a stimulating working environment and provide employees with good opportunities for professional and personal development.

The group seeks to achieve this through developing a strong, value-based performance culture, clear principles for leadership and an effective management and control system. In Statoil, the way in which results are achieved is as important as the results themselves. Corporate governance, our values, leadership model, operating model and corporate policies are described in *The Statoil Book*, which has been made available for all employees in Statoil ASA.

The group has global people policies to ensure consistent standards with due consideration of national laws and the special demands placed on our downstream segment. Through our global people development and deployment process, we seek to ensure a good match between professional interests and goals, while at the same time offering challenging and meaningful job opportunities. Statoil remains committed to providing financial and non-financial rewards that attract and motivate the right people, and we continue to focus on equal opportunities for all talents. We promote diversity among our employees. The importance of diversity is stated explicitly in Statoil's values and ethical codes of conduct. We try to create the same opportunities for everyone and do not tolerate discrimination or harassment of any kind in our workplace.

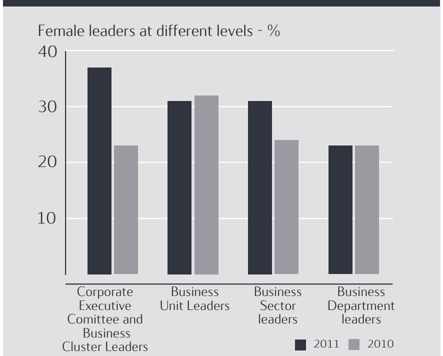
New hires by location



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, 43% of our new hires were women and 65% other nationalities than Norwegian.

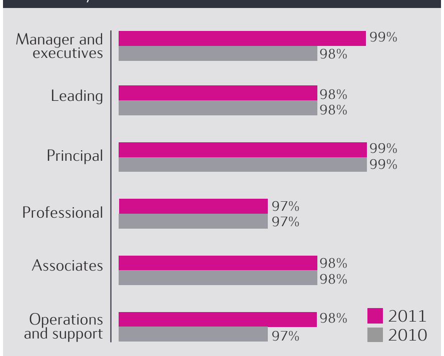
The reward system in Statoil is non-discriminatory and supports equal opportunities, which means that, given the same position, experience and performance, men and women will be at the same salary level. However, due to differences between women and men in types of positions and number of years' experience,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

Share of female leaders



In 2011, the overall percentage of women in the group was 37%. On Statoil ASA's board of directors, 40% of the members were women, as were 20% of the corporate executive committee. Through our development programmes, we aim to increase the number of female managers, and we endeavour to give equal representation to men and women in leadership development programmes. The total proportion of female managers in the Statoil group in 2011 was 31%, and, among managers under the age of 45, the proportion was 32% (number excluding the reporting segment SFR).

Salary ratio women to men



In Statoil ASA, we devote close attention to male-dominated 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%.

Statoil believes that being a global and sustainable company requires people with a global mindset. At year-end 2011, 41% of the managerial staff in the Statoil group held nationalities other than Norwegian. Outside Norway, Statoil aims to increase the number of people and managers who are locally recruited in order to reduce long-term, extensive use of expats in our business operations.

Share of non-Norwegian leaders

Building a culture characterised by a global mindset thus includes employing new role models with international experience in leading positions. During 2011, Statoil ASA went through a restructuring and deployed identified talents in new leading positions. The leadership pipeline represents a significant improvement in leadership diversity, and is summarised in the figures below.

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

	Number of employees			Women		
Geographical Region	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

On 31 December 2011, the Statoil group employed 31,715 permanent employees of which 20,021 were employed in Norway and 11,694 were employed outside Norway. Of the total number of employees 10,385 were employed in the Statoil Fuel & Retail group.

Environment and climate

Statoil works actively to limit the negative environmental impacts related to our operations.

Statoil is committed through its climate policy to contribute to sustainable development. We recognise that there is an accepted link between the use of fossil fuels and man-made climate change, and the climate policy takes into account the need for proactively combating global climate change in our operations, as well as evaluating the company's efforts on renewables and clean technology.

Statoil's climate policy sets out the principles for addressing the challenge of global warming and our ambition of maintaining the position as an industry leader in relation to sustainable development. Statoil's environmental management system is an integrated part of the overall management system and has been implemented in all our business planning and strategy development.

The most important group-wide indicators to measure environmental performance are emissions of oil spills, carbon dioxide and nitrogen oxides, energy consumption and the recovery rate for non-hazardous waste.

The volume of accidental oil spills was 44 cubic metres in 2011, the same as in 2010. The volume of other unintentional spills was 134 cubic metres in 2011, compared to 5,709 cubic metres in 2010. Several modification projects for further reductions are being implemented, and Statoil has established corporate-wide principles for oil spill response in relation to our operations. The group also continued an extensive research and development programme aimed at adapting its oil spill response to Arctic areas.

Carbon dioxide emissions have increased slightly from 13.4 million tonnes in 2010 to 13.7 million tonnes in 2011. Emissions from our international operations have increased in 2011 due to increased activities, mainly Leismer (Canada) and Peregrino (Brazil). The emissions from our midstream and downstream activities have increased, mainly due to the first year of ordinary operation of the combined heat and power plant at Mongstad. Emissions on the Norwegian continental shelf have decreased due to lower production. CO2 emissions from flaring have decreased from 1.3 million tonnes in 2010 to 1.2 million tonnes in 2011.

Nitrogen oxides emissions were 41.4 thousand tonnes in 2011, a decrease since 2010 when nitrogen oxides emissions were 42.3 thousand tonnes.

Energy consumption has increased slightly from 64.5 TWh in 2010 to 66.5 TWh in 2011. The energy consumption in our international operations increased in 2011 mainly because of increased activity in connection with the start-up on Leismer and Peregrino. The energy consumption at our land-based facilities increased, while energy consumption on the Norwegian continental shelf decreased due to lower production.

The recovery rate for non-hazardous waste has decreased from 51.9% in 2010 to 44.8% in 2011, mainly due to an increase in onshore drilling activity, with deposition of drilling waste to landfill. The hazardous waste recovery rate has decreased from 28.7% in 2010 to 17.2% in 2011. The decrease is due to an increase in onshore drilling activity, with deposition of drilling waste to landfill.

Society

Statoil has continuous focus on compliance, with policies and standards for social responsibility, human rights, ethics and anti-corruption throughout 2011.

Growing and sustaining our business depends on our ability to establish enduring and mutually beneficial relationships with the societies in which we operate. Wherever we operate, we make decisions based on how they affect our interests and those of the societies around us. Stakeholders include governments, communities, partners, contractors and suppliers, employees, customers and investors.

It is Statoil's responsibility to create value for our stakeholders. Living up to these responsibilities is required to support long-term profitability and consistency in complex environments. In line with our corporate policy on social responsibility, we are committed to:

- Making decisions based on how they affect our interests and the interests of the societies around us
- Ensuring transparency, anti-corruption and respect for human rights and labour standards, and
- Contributing to local content in our projects by developing skills and opportunities in the societies in which we operate.

Throughout 2011, we have continued to focus on compliance with policies and standards for social responsibility and ethics and anti-corruption across our operations. We make efforts to operate our business in a way that respects human rights and labour standards. We promote respect for fundamental labour rights and standards, such as decent wages, the regulation of working hours, the prohibition on child or forced labour, and freedom of association and collective bargaining. Furthermore, we actively support the Voluntary Principles of Security and Human Rights (VPSHR) and the United Nations Global Compact Principles.

Our commitment to the VPSHR is enshrined in our policy on corporate social responsibility, and the Principles are further integrated into our security procedures and management system. These procedures outline how security resources are managed and deployed, and underscore how important it is that all security personnel working on Statoil's behalf display universal respect for human rights, act within the law and comply with the company's rules on the use of force and firearms - in line with the UN Principles on the Use of Force and Firearms by Law Enforcement Officials and the UN Code of Conduct for Law Enforcement Officials.

We promote respect for fundamental labour rights and standards such as decent wages, regulated working hours, the prohibition on child or forced labour, and freedom of association and collective bargaining. While practices of association may vary in different countries in accordance with local standards, we endeavour to involve our employees and their appropriate representatives in development of the company.

In 2011, we have continued securing ethics and anti-corruption as an integrated part in business operations. The focus has been on the continued mainstreaming of our Ethics Code of Conduct throughout the organisation and on strengthening our ability to manage and mitigate integrity risks in our operations. We screen new investments, partners, contractors and suppliers for integrity and human rights risks, and implement strict requirements for integrity due diligence (IDD) to improve our processes for managing integrity risks in our business relationships.

Through our core activities and the benefits that result from these, we aim to contribute to sustainable development in the countries and communities in which we operate. We wish to be known for our high ethical standards and our commitment to transparency and openness, and we have zero tolerance for ethics violations in our operations.

Our business also generates significant tax revenues for governments. In 2011, we made total payments and contributions to governments estimated at NOK 191 billion, of which an estimate of 63% was paid to the Norwegian government. Direct and indirect taxes paid in Norway amounted to NOK 119.8 billion, and direct and indirect taxes paid outside Norway totalled NOK 30.8 billion in 2011. Based on production sharing agreements, depending on the value of petroleum and the requirements stipulated in the agreements, we also made in-kind contributions (profit oil) estimated at NOK 40 billion.

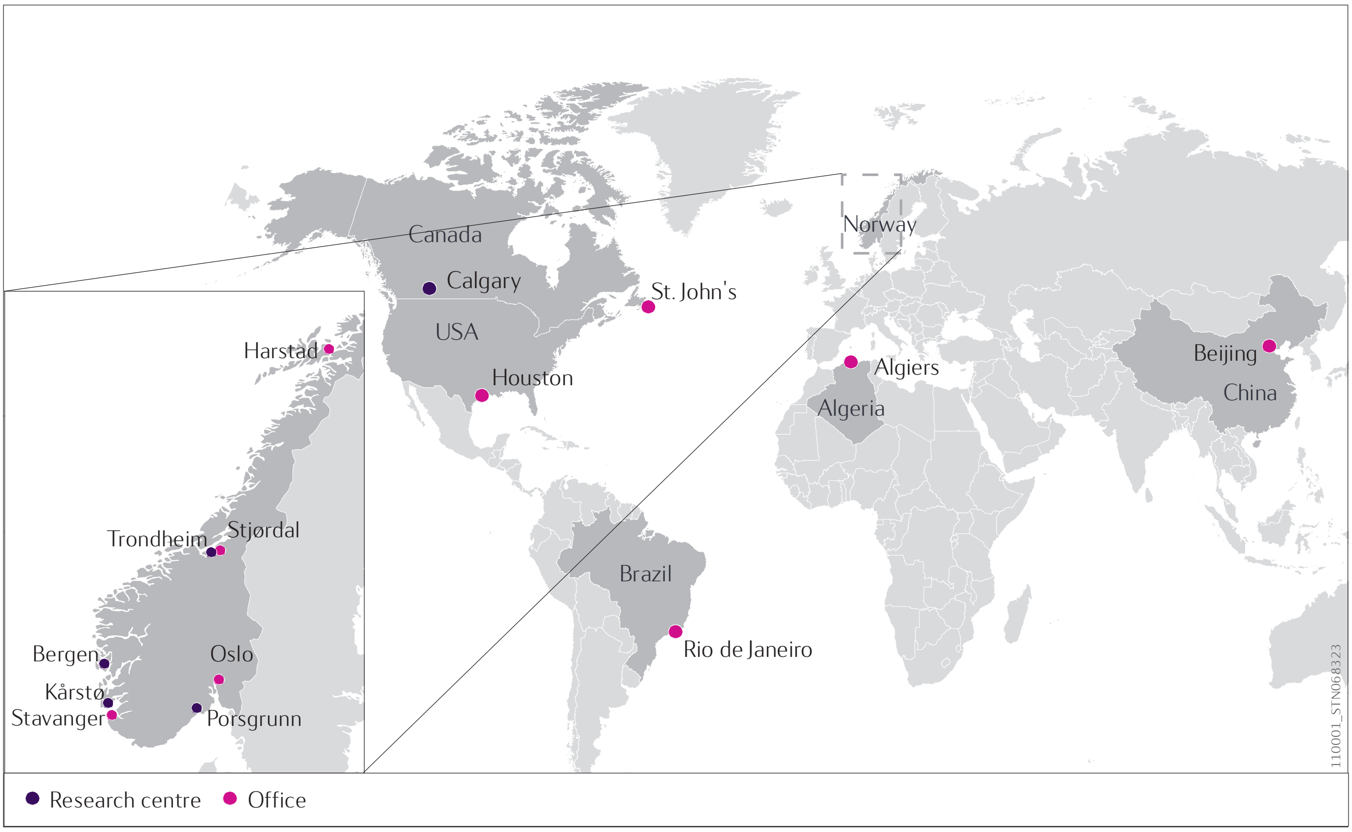
To achieve our aim of increasing local procurement, we invest in local enterprises and also support capacity building initiatives and skills development for local employees and communities to provide them with the right skills and expertise, standards and certifications required to compete successfully and work in the oil and gas industry.

Research and Development

Statoil is a technology intensive company and research and development is an integral part of the strategy. Innovation and technological development are essential to our growth and sustainability.

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.

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 Norwegian continental shelf and internationally. Statoil's research and development portfolio is organised in seven programmes covering the main upstream building blocks where Statoil is growing. An academia programme addresses cooperation with universities and research institutes. Cooperation with external partners such as academic institutions, research and development institutes and suppliers is crucial in relation to technology. Statoil has four research centres in Norway, a heavy oil technology centre in Canada and a research and development office in Beijing (China). In addition, we have expanded the research and development activities with offices in Rio de Janeiro (Brazil), Houston (USA) and St. John's (Canada), close to many of our international operations.



The business potential of technologies that address increased recovery is significant. Statoil is focusing 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. Statoil is 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.

Research and development expenditures have been approximately NOK 2.1 billion per year for the last three years.

Group and market outlook

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.

Statoil expects 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. Statoil believes 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.

Statoil continues 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 and contract structures, 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.

Board developments

No changes have been made to the composition of the board or the sub-committees throughout 2011.

The board held 15 meetings in 2011. The attendence at the board meetings was 93.3%.

The board's audit committee held six meetings in 2011. The attendance at the committee's meetings was 91.6%.

The board's compensation committee held 7 meetings in 2011. The attendance at the committee's meetings was 85.7%.

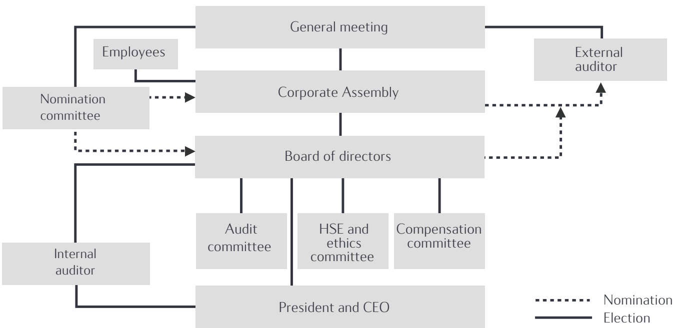
The board's HSE and ethics committee held 4 meetings in 2011. The attendance at the committee's meetings was 87.5%.

Whole or parts of the board have visited several Statoil locations througout 2011, inter alia the Mongstad facility and the offshore platform Gullfaks C in Norway, as well as facilities in Canada and the US. The purpose of such excursions is to improve the board's insight and knowledge about Statoil's commercial activities.

Board statement on corporate governance

To ensure sound corporate practice, Statoil's organisation is structured and managed in accordance with the Norwegian Code of Practice for Corporate Governance.

Nominations and elections - Statoil ASA



Statoil's board of directors actively adheres to good corporate governance standards and will at all times ensure that Statoil either complies with the Norwegian Code of Practice for Corporate Governance (the "Code") or explains possible deviations from the Code in the board statement on corporate governance. The topic of corporate governance is subject to annual assessment and discussion by the board, which has also considered the text of the board statement at a board meeting. The Code may be found at www.nues.no.

The Code covers 15 topics, and the board statement covers each of these topics and describes Statoil's adherence to the Code. The board statement describes the fundament and principles for Statoil's corporate governance structure, while more detailed factual information may be found at our website, in our annual form 20-F to the US Securities and Exchange Commission, in the annual report and in our sustainability reporting. Links to relevant information at our website are included in the statement.

The statement from the board of directors is provided as a separate report in the 2011 Annual Report download centre (www.statoil.com/downloads).

Stavanger, 13 March 2012

THE BOARD OF DIRECTORS OF STATOIL ASA

Svein Rennemo

SVEIN RENNEMO
CHAIR

Marit Arnstad

MARIT ARNSTAD
DEPUTY CHAIR

Lill-Heidi Bakkerud

LILL-HEIDI BAKKERUD

BJØRN TORE GODAL

ROY FRANKLIN

Lady Barbara Judge

LADY BARBARA JUDGE

Einar Arne Iversen

EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

Jakob Stausholm

JAKOB STAUSHOLM

Morten Svaan

MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

Statement on compliance

Today, the board of directors, the chief executive officer and the chief financial officer reviewed and approved the board of directors' report and the Statoil ASA consolidated and separate annual financial statements as of 31 December 2011.

To the best of our knowledge, we confirm that:

- the Statoil ASA consolidated annual financial statements for 2011 have been prepared in accordance with IFRSs and IFRICs as adopted by the European Union (EU), IFRSs as issued by the International Accounting Standards Board (IASB) and additional Norwegian disclosure requirements in the Norwegian Accounting Act, and that
- the separate financial statements for Statoil ASA for 2011 have been prepared in accordance with the Norwegian Accounting Act and Norwegian Accounting Standards, and that
- the board of directors' report for the group and the parent company is in accordance with the requirements in the Norwegian Accounting Act and Norwegian Accounting Standard no 16, and that
- the information presented in the financial statements gives a true and fair view of the company's and the group's assets, liabilities, financial position and results for the period viewed in their entirety, and that
- the board of directors' report gives a true and fair view of the development, performance, financial position, principle risks and uncertainties of the company and the group.

Stavanger, 13 March 2012

THE BOARD OF DIRECTORS OF STATOIL ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

BJØRN TORE GODAL

ROY FRANKLIN

LADY BARBARA JUDGE

EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

JAKOB STAUSHOLM

MORTEN SVAAN

TORGRIM REITAN
CHIEF FINANCIAL OFFICER

HELGE LUND
PRESIDENT AND CEO

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:	12			
Basic		24.76	11.97	5.75
Diluted		24.70	11.94	5.74

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK million)	Note	2011	2010 (restated)	2009 (restated)
		For the year ended 31 December		
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				
Non-current assets				
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
Current assets				
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				
Equity				
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	21	285,155	226,395	200,118
Non-current liabilities				
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
Total non-current liabilities		312,323	271,338	250,932
Current liabilities				
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
Total current liabilities		171,129	136,305	112,054
Liabilities directly associated with the assets classified as held for sale	5	0	9,223	0
Total liabilities		483,452	416,866	362,986
TOTAL EQUITY AND LIABILITIES		768,607	643,261	563,104

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

							Other reserves				
(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	Available for sale financial assets	Currency translation adjustments	Statoil shareholders' equity	Non-controlling interests	Total equity
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

							Other reserves				
(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	Available for sale financial assets	Currency translation adjustments	Statoil shareholders' equity	Non-controlling interests	Total equity
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

							Other reserves				
(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	Available for sale financial assets	Currency translation adjustments	Statoil shareholders' equity	Non-controlling interests	Total equity
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	For the year ended 31 December 2011	2010 (restated)	2009 (restated)
OPERATING ACTIVITIES				
Income before tax		**213,841**	136,826	114,910
Adjustments to reconcile net income to net cash flows provided by operating activities:				
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)
Changes in working capital (other than cash and cash equivalents):				
- (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	2011	2010 (restated)	2009 (restated)
		For the year ended 31 December		
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.

Notes to the Consolidated financial statements

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway.

The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil'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.

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.

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

	2010			2009		
(in NOK million)	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 At 31 December (as reported)	2010 Restatement	2010 At 31 December (as restated)	2009 At 31 December (as reported)	2009 Restatement	2009 At 31 December (as restated)
ASSETS						
Non-current assets						
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
Current assets						
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 At 31 December (as reported)	2010 Restatement	2010 At 31 December (as restated)	2009 At 31 December (as reported)	2009 Restatement	2009 At 31 December (as restated)
EQUITY AND LIABILITIES						
Equity						
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
Non-current liabilities						
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
Current liabilities						
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.

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

(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

(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

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

Major customers

Statoil does not have transactions with single external customers where revenues amount to more than 10% of the group's total revenues.

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 December2011
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 Skirne- 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.

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.

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 Remuneration

(in NOK million, except average number of man-labour years)	2011	For the year ended 31 December 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*.

Management remuneration for 2011 is presented in note 5 *Remuneration* in the financial statements of the parent company, Statoil ASA.

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.

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.

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 liabilites	(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.

11 Income taxes

Significant components of income tax expense were as follows

(in NOK million)	2011	For the year ended 31 December 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)	2011	For the year ended 31 December 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

		At 31 December	
(in NOK million)	2011	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.

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.

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
Transfered 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)	For the year ended 31 December 2011	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.

14 Intangible assets

(in NOK million)	Exploration expenditure	Goodwill	Other	Total
Cost at 31 December 2010	38,351	4,353	2,395	45,099
Transfered 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.

	For the year ended 31 December		
(in NOK million)	2011	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

	For the year ended 31 December		
(in NOK million)	2011	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.

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*.

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.

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

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 Statoils 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*.

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.

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 equivalents in the Consolidated statement of cash flows.

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.

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 31 December 2011	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)	At 31 December 2011	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*.

	At 31 December 2011	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

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)	2011	For the year ended 31 December 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

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.

	Disability in %		Mortality in %		Expected lifetime	
Age	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.

	Discount rate		Rate of compensation increase		Social security base amount		Expected rate of pension increase	
(in NOK billion)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%
Changes in:								
Projected benefit obligation								
at 31 December 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.

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*.

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*.

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.

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.

	Operating leases						Finance leases		
(in NOK million)	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

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*.

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.

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.

					Fair value through profit or loss			
(in NOK million)	Note	Loans and receivables	Available-for-sale	Hedge accounting	Held for trading	Fair value option	Non-financial assets	Total carrying amount
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: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
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: Held for trading	Fair value through profit or loss: Fair value option	Non-financial assets	Total carrying amount
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.

(in NOK million)	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Hedge accounting	Fair value through profit or loss: 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

(in NOK million)	Fair value through profit or loss: Held for trading	Fair value through profit or loss: Hedge accounting	Fair value through profit or loss: 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

(in NOK million)	Fair value through profit or loss: 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	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

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

32 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 it's 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

	Norway	Eurasia excluding Norway	Africa	Americas	Total
			Net proved oil and NGL reserves in million barrels		
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

	Norway	Eurasia excluding Norway	Africa	Americas	Total
	Net proved oil, NGL and gas reserves in million barrels oil equivalent				
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

Parent company financial statements

STATEMENT OF INCOME STATOIL ASA - NGAAP

(in NOK million)	Note	For the year ended 31 December 2011	2010
REVENUES AND OTHER INCOME			
Revenues	4	466,274	384,422
Net income from subsidiaries and other equity accounted companies	12	66,408	37,190
Other income		74	12
Total revenues and other income		532,756	421,624
OPERATING EXPENSES			
Purchases [net of inventory variation]		(449,765)	(368,465)
Operating expenses		(9,153)	(9,575)
Selling, general and administrative expenses		(6,381)	(6,177)
Depreciation, amortisation and net impairment losses	11	(761)	(796)
Exploration expenses		(762)	(786)
Total operating expenses		(466,822)	(385,799)
Net operating income		65,934	35,825
FINANCIAL ITEMS			
Net foreign exchange gains (losses)		3,833	(2,553)
Interest income and other financial items		3,421	4,677
Interest and other finance expenses		(4,859)	(2,811)
Net financial items	9	2,395	(687)
Income before tax		68,329	35,138
Income tax	10	24	2,591
Net income		68,353	37,729

BALANCE SHEET STATOIL ASA - NGAAP

(in NOK million)	Note	At 31 December 2011	At 31 December 2010
ASSETS			
Non-current assets			
Property, plant and equipment	11	5,404	5,096
Intangible assets		184	15
Investments in subsidiaries and other equity accounted companies	12	294,488	267,687
Deferred tax assets	10	6,576	3,978
Pension assets	19	3,865	5,087
Prepayments and financial receivables*	13	1,300	925
Receivables from subsidiaries and other equity accounted companies	13	70,145	89,021
Total non-current assets		381,962	371,809
Current assets			
Inventories	14	13,168	15,021
Trade and other receivables	15	53,026	45,221
Receivables from subsidiaries and other equity accounted companies		67,143	40,805
Current tax receivables	10	0	389
Derivative financial instruments	3	816	1,645
Financial investments	13	14,620	5,230
Cash and cash equivalents	16	28,108	18,131
Total current assets		176,881	126,442
TOTAL ASSETS		558,843	498,251

* Including a receivable related to Naturkraft AS of NOK 541 million. In the comparable figures for 2010 this receivable has been reclassified from *Prepayments and financial receivables* to non-current and current *Receivables from subsidiaries and other equity accounted companies.*

BALANCE SHEET STATOIL ASA - NGAAP

(in NOK million)	Note	At 31 December 2011	At 31 December 2010
EQUITY AND LIABILITIES			
Equity			
Share capital		7,972	7,972
Treasury shares		(20)	(18)
Additional paid-in capital		17,330	17,330
Retained earnings		139,068	107,706
Reserves for valuation variances		79,839	61,935
Total equity	17	244,189	194,925
Non-current liabilities			
Bonds, bank loans and finance lease liabilities	18	99,525	90,301
Derivative financial instruments	3	1,031	1,228
Liabilities to subsidiaries		78	63
Pension liabilities	19	25,982	21,497
Provisions and other liabilities	20	1,235	1,102
Total non-current liabilities		127,851	114,191
Current liabilities			
Trade and other payables	21	39,551	32,129
Current tax payable		889	0
Bonds, bank loans, commercial papers and collateral liabilities	22	14,179	8,450
Derivative financial instruments	3	2,025	571
Dividends payable	17	20,705	19,890
Liabilities to subsidiaries		109,454	128,095
Total current liabilities		186,803	189,135
Total liabilities		314,654	303,326
TOTAL EQUITY AND LIABILITIES		558,843	498,251

STATEMENT OF CASH FLOWS STATOIL ASA - NGAAP

(in NOK million)	For the year ended 31 December 2011	2010
OPERATING ACTIVITIES		
Income before tax	68,329	35,138
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortisation and net impairment losses	762	796
(Gains) losses on foreign currency transactions and balances	6,304	1,589
(Gains) losses on sales of assets and other items	(36,445)	(10,384)
Changes in working capital (other than cash and cash equivalents):		
· (Increase) decrease in inventories	1,853	(3,045)
· (Increase) decrease in trade and other receivables	(9,521)	(13,168)
· Increase (decrease) in trade and other payables	7,380	6,855
· Increase (decrease) in receivables/liabilities to/from subsidiaries	6,557	2,916
(Increase) decrease in current financial investments	(9,389)	(3,325)
(Increase) decrease in net financial derivative instruments	(403)	(2,184)
Taxes paid	502	(2,928)
(Increase) decrease in non-current items related to operating activities	(1,041)	2,290
Cash flows provided by operating activities	34,888	14,550
INVESTING ACTIVITIES		
Cash flows provided by (used in) investing activities	(8,040)	(4,371)*
FINANCING ACTIVITIES		
New non-current loans	10,053	11,579
Repayment of non-current loans	(4,055)	(2,774)
Dividend paid	(19,891)	(19,095)
Treasury shares purchased	(408)	(294)
Net current loans, bank overdrafts and other	4,792	951
Increase (decrease) in financial receivables and payables to/from subsidiaries	(6,579)	2,926
Cash flows provided by (used in) financing activities	(16,088)	(6,707)
Net increase (decrease) in cash and cash equivalents	10,760	3,472
Effect of exchange rate changes on cash and cash equivalents	(783)	199
Cash and cash equivalents at the beginning of the period	18,131	14,460
Cash and cash equivalents at the end of the period	28,108	18,131
Interest paid	2,061	2,172
Interest received	1,514	1,131

* 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.

Notes to the Financial statements for Statoil ASA

1 Organisation

Statoil ASA, originally Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway.

The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

Statoil ASA's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products, and other forms of energy. The activities are also carried out through participation in or cooperation with other companies.

Statoil ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA).

With effect from 1 January 2009, Statoil ASA transferred the ownership of its net assets on the Norwegian Continental Shelf (NCS) to Statoil Petroleum AS, a 100% owned operating subsidiary. Following the transfer, all the Statoil group's NCS net assets are owned by Statoil Petroleum AS.

The functional currency of Statoil ASA is USD, while its presentation currency is NOK.

2 Significant accounting policies

Statement of compliance
The financial statements of Statoil ASA ("the company") are prepared in accordance with the Norwegian Accounting Act of 1998 and good accounting practice (NGAAP).

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 financial statements.

The Statement of cash flows has been prepared in accordance with the indirect method.

Subsidiaries, associated companies and jointly controlled entities
Shareholdings and interests in subsidiaries, associated companies (companies in which Statoil ASA does not have control, or joint control, but has the ability to exercise significant influence over operating and financial policies; generally when the ownership share is between 20 and 50%) and jointly controlled entities are accounted for using the equity method.

Expenses related to the Statoil group as operator of jointly controlled assets
Indirect operating expenses incurred by the company, such as personnel expenses, are accumulated in cost pools. Such expenses are allocated in part on an hours incurred cost basis to Statoil Petroleum AS and to licences where Statoil Petroleum AS is operator. Costs allocated to Statoil Petroleum AS and Statoil group jointly controlled assets (licences) in this manner reduce the expenses in the company's Statement of income.

Asset transfers between Statoil ASA and its subsidiaries
Transfers of assets and liabilities between Statoil ASA and entities directly or indirectly controlled by Statoil ASA are accounted for at the carrying amounts of the assets and liabilities transferred.

Foreign currency translation
Transactions in foreign currencies (those other than functional currency) are translated to USD at the foreign exchange rate at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to USD at the foreign exchange rate at the balance sheet date. Foreign exchange differences arising on translation are recognised in the Statement of income. 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 financial statements, the Statement of income and Balance sheet in functional currency are translated into the presentation currency, Norwegian kroner (NOK). The assets and liabilities of the company and net assets and liabilities of equity accounted investments 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 from the company and the net income from equity accounted investments are translated using the foreign exchange rates on the dates of the transactions.

Revenue recognition

Revenues associated with sale and transportation of crude oil, petroleum and chemical products, and other merchandise are recorded when title and risk pass to the customer, which normally is at the point of delivery of the goods based on the contractual terms of the agreements.

Sales and purchases of physical commodities, which are not settled net, are presented on a gross basis as *Revenues* and *Purchases [net of inventory variation]* in the Statement of income. Activities related to the trading of commodity based derivative instruments are reported on a net basis, with the margin included in *Revenues*.

Transactions with the Norwegian State and with Statoil Petroleum AS

Statoil ASA markets and sells the Norwegian State's and Statoil Petroleum AS' 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's and Statoil Petroleum AS' 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 and Statoil Petroleum AS' account and risk, the state's and Statoil Petroleum AS' production of natural gas. This sale and related expenditures refunded by the State and by Statoil Petroleum AS are recorded net in Statoil ASA's financial statements.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of Statoil ASA. The accounting policy for pensions and share-based payments is described below.

Share-based payments

The company 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 salary expense and recognised as an equity transaction (included in additional paid-in capital).

Research and development

Research and 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; 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 Statement of income for the year comprises current and deferred tax expense. Income tax is recognised in the Statement of income except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

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 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 profits will be available against which the asset can be utilised. In order for a deferred tax asset to be recognised based on future taxable profits, convincing evidence is required, taking into account the existence of contracts, observable prices in active markets, expected volatility of trading profits and similar facts and circumstances.

Property, plant and equipment

Property, plant and equipment are stated 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 a decommissioning obligation, if any, and, for qualifying assets, borrowing costs.

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 company, 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.

Depreciation is calculated on the basis of the assets' 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.

The estimated useful lives of property, plant and equipment are reviewed on an annual basis and changes in useful lives are accounted for prospectively. An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in *Other income* or *Operating expenses*, respectively, in the period the item is derecognised.

Leases

Leases in terms of which the company assumes substantially all the risks and rewards of the ownership are reflected as finance leases within *Property, plant and equipmen*t and *Bonds, bank loans and finance lease liabilities*. All other leases are classified as operating leases and the costs are recognised as 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 company.

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. 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.

The company distinguishes between leases, which imply the right to use a specific asset for a period of time, and capacity contracts, which confer on the company the right to and the obligation to pay for certain capacity volume availability related to transport, terminalling, storage etc. Such capacity contracts that do not involve specified single assets or that do not involve substantially all the capacity of an undivided interest in a specific asset are not considered by the company to qualify as leases for accounting purposes. Capacity payments are reflected as *Operating expenses* in the Statements of income in the period for which the capacity contractually is available to the company.

Financial assets

Financial assets representing loans and receivables are carried at amortised cost using the effective interest method. Trading securities classified as current financial investments are recognised at fair value with gains and losses reflected in the Statement of income.

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 the company will be unable to recover the balances in full.

Financial assets are presented as current if these contractually will expire or otherwise are expected to be recovered within 12 months after the balance sheet date, or if these are financial instruments held for the purpose of being traded. Other financial assets expected to be recovered more than 12 months after the balance sheet date are classified as non-current.

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.

Derivative financial instruments

The following accounting policies are applied for the principal financial instruments and commodity-based derivatives:

Currency swap agreements

Currency swaps are recognised at fair value in the Balance sheet and changes in fair value are recognised in the Statement of income.

Interest rate swap agreements

Interest rate swap agreements are valued according to the lower of cost or market principle.

Commodity-based derivatives

Commodity-based derivatives traded on organised exchanges are valued at fair market value and the resulting gains and losses are recognised in the Statement of income. Other commodity-based derivatives are valued according to the lower of cost or market principle.

Cash and cash equivalents

Cash and cash equivalents include cash, bank deposits and all other monetary instruments with three months or less to maturity at the date of purchase.

Impairment

Impairment of property, plant and equipment

The company 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.

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 the company's estimated value in use, which is determined using a discounted cash flow model. 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 the company's post tax weighted average cost of capital (WACC).

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 of financial assets
The company assesses at each balance sheet date whether a financial asset or group of financial assets is impaired. 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 with the amount of loss recognised in the Statement of income.

Any subsequent reversal of an impairment loss is recognised in the Statement of income.

Financial liabilities
Interest-bearing loans and borrowings are initially recognised at cost and subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs as well as discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised respectively in *Interest income and other financial items* and *Interest and other finance expenses*.

Financial liabilities are presented as current if the liabilities are due to be settled within 12 months after the balance sheet date, or if these are financial instruments 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.

Pension liabilities
Statoil ASA has pension plans that provide employees with a defined pension benefit upon retirement. The benefit to be received by employees generally depends on many factors including length of service, retirement date and future salary increases.

The company'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 to the terms of the company's obligations and established on the basis of 10-years' Norwegian government bonds. The calculation is performed by an external actuary. Current service cost is an element of net periodic pension cost and is 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 charged in part to Statoil Petroleum AS and to licences where Statoil Petroleum AS is operator on the Norwegian Continental Shelf on an hours incurred basis. The remaining pension cost is recognised in the company's 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 resulting 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 company's retained earnings in the period in which they occur. Due to Statoil ASA's functional currency being USD, the significant part of the company's pension obligations will be payable in a foreign currency (ie. NOK). Actuarial gains and losses as a consequence include the impact of exchange rate fluctuations.

Provisions and contingent assets and liabilities
Provisions are recognised when the company 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 the control of the company (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 financial statements in the period in which the inflow of economic benefits becomes virtually certain.

Onerous contracts
The company recognises as provisions the obligation under contracts defined as onerous. Contracts are deemed to be onerous if the unavoidable costs of meeting the obligations under the contract exceed 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.

Trade and other payables
Trade and other payables are carried at payment or settlement amounts.

Use of estimates
Preparation of the financial statements requires the company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingencies. Actual results may ultimately differ from the estimates and assumptions used.

The nature of Statoil's operations, and the many countries in which Statoil operates, is subject to changing economic, regulatory and political conditions. Statoil does not believe it is vulnerable to the risk of a near-term severe impact as a result of any concentration of its activities.

3 Financial risk management and derivatives

Financial risks
Statoil ASA's activities expose the company to the following financial risks:

- Market risk (including commodity price risk, currency risk and interest rate risk)
- Credit risk
- Liquidity risk

Market risk
Statoil ASA 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.

Statoil ASA has established guidelines for entering into derivative contracts in order to manage the commodity price, foreign currency rate and interest rate risk. The company 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 constitutes Statoil ASA's most important market risk and is monitored everyday against established mandates as defined by the governing policies. To manage the commodities price risk Statoil ASA 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 InterContinental 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 Nordpool) forwards, and futures traded on the NYMEX and ICE.

The term of 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.

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

Foreign exchange risk is managed at corporate level in accordance with policies and mandates.

Statoil ASA's cash flows derived from oil and gas sales, operating expenses and capital expenditures, are mainly in USD, but taxes and dividends are in NOK. Accordingly, the entity's currency management is primarily linked to secure tax and dividend payments in NOK. This means that the entity regularly purchase substantial NOK amounts on a forward basis using conventional derivative instruments.

At the end of 2011 and 2010 the following currency risk sensitivities have been calculated by assuming a 12% change in the foreign currency exchange rates. An increase in the foreign exchange rates by 12% means that the transaction currency has strengthened in value.

(in NOK million)	EUR	GBP	CAD	NOK	SEK	DKK
At 31 December 2011						
Net gains/(losses) (12% sensitivity)	118	(93)	0	10,935	(13)	111
Net gains/(losses) (-12% sensitivity)	(118)	93	0	(10,935)	13	(111)
At 31 December 2010						
Net gains/(losses) (12% sensitivity)	(814)	(388)	(5)	10,942	88	39
Net gains/(losses) (-12% sensitivity)	814	388	5	(10,942)	(88)	(39)

Interest rate risk
Statoil ASA has assets and liabilities with variable interest rate that expose the entity to cash flow risk caused by market interest rate fluctuations. The entity enters into interest rate derivatives, particularly interest rate swaps, to alter interest rate exposures, to lower expected funding costs over time and to diversify sources of funding. By using the fixed interest rate debt market when issuing new debt and at the same time altering the interest rate exposure by entering into interest rate swaps, funding sources become more diversified than by only being able to use the US floating rate debt market.

Statoil ASA principally manages the company's interest rates by converting a portion of cash flows from the long-term debt portfolio issued with fixed coupon rates into floating rate interest payments. Bonds are normally issued at fixed rates in local currency (JPY, EUR, CHF, GBP and USD). These bonds are converted to floating USD bonds by using interest rate- and currency swaps. Statoil ASA's interest rate policy includes a mandate to keep a portion of the long term debt at fixed interest rates. For more detailed information about Statoil ASA's long term debt-portfolio see note 18 *Bonds, bank loans and finance lease liabilities*.

For the interest rate risk sensitivity a change of 1.5 percentage point in the interest rates have been used in the calculation by end of 2011. 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. A decline in the interest rates results in a gain while increased interest rates result in a loss. Included in the interest rate sensitivity are changes in fair value of interest rate derivative financial instruments currently recognised at fair value in the Balance sheet since the fair value are lower than the cost price for the instruments at year end 2011 and 2010. When the interest rate declines the fair value of these instruments will be higher than the cost price and therefore the full change in fair value due to an interest rate decline will not be recognised in the Statement of income. The estimated gains and losses are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2011		
Interest rate risk (1.5 percentage point sensitivity)	579	(579)
At 31 December 2010		
Interest rate risk (-0.5 percentage point sensitivity)	602	
Interest rate risk (1.5 percentage point sensitivity)		(1,805)

Credit risk
Credit risk is the risk that Statoil ASA's customers or counterparties will cause the company 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
- Internal credit rating process
- Credit risk mitigation tools
- A continuous monitoring and managing of credit exposures

Prior to entering into transactions with new counterparties, the 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 minimum annually and continuously monitored. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial and other relevant business information. In addition, Statoil ASA evaluates any past payment performance, the counterparties' size and business diversification, and the inherent industry risk. The internal credit ratings reflect Statoil ASA's assessment of the counterparties' credit risk. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics. Credit mandates define acceptable credit risk thresholds and are endorsed by management and regularly reviewed with regard to changes in market conditions.

Statoil ASA 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 ASA has pre-defined limits for the minimum average credit rating allowed at any given time on the group portfolio level as well as maximum credit exposures for individual counterparties. Statoil ASA monitors the portfolio on a regular basis and individual exposures versus limits on a daily basis. The total credit exposure portfolio of Statoil ASA 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 the company's credit exposure is with investment grade counterparties.

The following table contains the carrying amount of Statoil ASA's derivative financial instruments, except for exchange traded derivative financial instruments, split by our assessment of the counterparty's credit risk.

	At 31 December	
(in NOK million)	2011	2010
Investment grade, rated A or above	606	1,561
Other investment grade	115	0
Non investment grade or not rated	16	30
Total	737	1,591

As of 31 December 2011 and 2010 cash was held as collateral to mitigate a portion of Statoil ASA's credit exposure.

Liquidity risk

Liquidity risk is the risk that Statoil ASA 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 ASA has sufficient funds available at all times to cover its financial obligations.

Liquidity and funding are managed at the corporate level, ensuring adequate liquidity to cover group operational requirements. The challenging market conditions during the last couple of years have led to an increased focus and attention on credit and liquidity risk throughout Statoil's entire organisation. In order to secure necessary financial flexibility, which includes meeting Statoil ASA's financial obligations, Statoil ASA maintains what it believes to be a conservative liquidity management policy. To secure financial flexibility and identify future long-term financing needs, Statoil carries out three-year cash forecasts at least monthly.

Statoil ASA's operating cash flows are significantly impacted by the volatility in the oil and gas prices. During 2011 the overall liquidity position remained strong.

The main cash outflows are the annual dividend payment and the annual tax payments. 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.

For information about Statoil ASA's non-current financial liabilities, see note 18 *Bonds, bank loans and finance lease liabilities.*

Mainly all of Statoil ASA's financial liabilities related to derivative financial instruments, both exchange traded and non-exchange traded commodity-based derivatives together with financial derivatives, with the exception of some interest rate derivatives classified as non-current in the Balance sheet, fall due within one year, based on the underlying delivery period of the contracts included in the portfolio. The interest rate derivatives classified as non-current in the Balance sheet fall due from 2015 till 2031.

Fair value measurement of derivative financial instruments

Statoil ASA measures derivative financial instruments at fair value if the instruments are part of a trading portfolio and traded at an authorised exchange. This might typically be for forward contracts traded at the Nordic electricity exchange NASDAQ OMX Oslo (formaly Nordpool). Other derivative financial instruments are recognised in the Balance sheet at the lowest of the cost price and the fair value. Changes in the carrying value of the derivative financial instruments are recognised in the Statements of income either within *Revenues* or within the *Net financial items*. Statoil ASA's portfolio of derivative financial instruments consists of commodity based derivative contracts as well as interest rate and foreign exchange rate derivative instruments.

The following table contains the estimated fair values and the net carrying amounts of Statoil ASA's derivative financial instruments except for the interest rate derivatives and the cross currency interest rate derivatives where the table only contains the fair value adjustments while the accrued interests are presented within *Bonds, bank loans, commercial papers and collateral liabilities* and the currency revaluations are presented within *Bonds, bank loans and finance lease liabilities*.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net fair value
At 31 December 2011			
Foreign currency instruments	323	(1,112)	(789)
Interest rate instruments	0	(1,369)	(1,369)
Crude oil and refined products	200	(236)	(36)
Natural gas and electricity	293	(339)	(46)
Total	816	(3,056)	(2,240)
At 31 December 2010			
Foreign currency instruments	1,462	(269)	1,193
Interest rate instruments	0	(1,235)	(1,235)
Crude oil and refined products	0	0	0
Natural gas and electricity	183	(295)	(112)
Total	1,645	(1,799)	(154)

In addition to the fair value of financial derivative instruments recognised in the Balance sheet, Statoil ASA has entered into interest rate swap and cross currency swap agreements where the fair value at year end 2011 and 2010 was higher than the cost, hence the fair value adjustments related to these agreements are not recognised in the Balance sheet. At 31 December 2011 the fair value adjustments not recognised were NOK 12.3 billion. By end of 2010 the fair value adjustments not recognised were NOK 5.0 billion.

When determining the fair value of the derivative financial instruments, Statoil ASA uses prices quoted in an active market to the extent possible. When this is not available, the company uses inputs that either directly or indirectly are observable in the market as a basis for valuation techniques such as discounted cash flow analysis or pricing models.

The following table summarises the basis for Statoil ASA's fair value measurement for all financial derivative instruments recognised in Statoil ASA's Balance sheet. For the interest rate derivatives and the cross currency interest rate derivatives the table only contain the fair value adjustments.

(in NOK million)	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)	0	0	0	0
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	816	(1,031)	(2,025)	(2,240)
Fair value based on unobservable inputs (Level 3)	0	0	0	0
Total fair value	816	(1,031)	(2,025)	(2,240)
At 31 December 2010				
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	0	0	0	0
Fair value based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability (Level 2)	1,645	(1,228)	(571)	(154)
Fair value based on unobservable inputs (Level 3)	0	0	0	0
Total fair value	1,645	(1,228)	(571)	(154)

Level 1, fair value based on prices quoted in an active market for identical assets or liabilities, refers to the fair value of financial instruments actively traded where the values recognised in Statoil ASA's Balance sheet are determined based on observable prices on identical instruments. This category will in most cases only be relevant for investments in listed equity securities or goverment 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 ASA's non-standardised contracts which fair values are determined on the basis of price inputs that are from observable market transactions. This will typically be when Statoil ASA uses forward prices on crude oil, natural gas, interest rates, and foreign exchange rates as inputs into valuation models to determining the fair value of its derivative financial instruments.

Level 3, fair value based on unobservable inputs, refers to fair values calculated based on input and assumptions that are not from observable market transactions. The fair values presented in this category will mainly be based on internal assumptions. The internal assumptions are only used due to the absence of quoted price from an active market or other observable price inputs for the financial instruments subject to the valuation.

4 Revenues

In presenting information on the basis of geographical areas, revenue from external customers is attributed to countries from which Statoil ASA derives revenues.

Revenues by counterparties

(in NOK million)	For the year ended 31 December 2011	2010
Norway	29,469	32,404
Europe	266,859	213,787
North America	101,330	76,041
Other	68,616	62,190
Revenues	466,274	384,422

(in NOK million)	For the year ended 31 December 2011	2010
Revenues third party	383,194	318,033
Intercompany revenues	83,080	66,389
Revenues	466,274	384,422

5 Remuneration

(in NOK million, except average number of man-labour years)	For the year ended 31 December 2011	2010
Salaries	16,574	15,807
Pension costs	3,416	3,742
Payroll tax	2,598	2,428
Other compensations	2,061	1,760
Total	24,649	23,737
Average number of man-labour years	18,337	17,583

Board of directors remuneration in 2011 (in NOK thousand)

Members of the board		Board remuneration	Audit committee	Compensation committee	HSEE committee	Total remuneration
Svein Rennemo	Chair of the board	632		38		670
Marit Arnstad	Deputy chair	403			15	418
Grace Reksten Skaugen	Board member	321		75		396
Roy Franklin	Board member	437	115		63	615
Jakob Stausholm	Board member	321	178			499
Bjørn Tore Godal	Board member	321		53	31	405
Lady Barbara Judge	Board member	418	115			533
Lill-Heidi Bakkerud	Board member	321			31	352
Morten Svaan	Board member	321	115			436
Einar Arne Iversen	Board member	321				321
Geir Nilsen*	Deputy member	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: Base pay 1)	Fixed remuneration: LTI 2)	Annual variable pay	Taxable benefits in kind	Taxable reimburse-ments	Taxable salary	Non-taxable benefits in kind	Non-taxable reimburse-ments	Non-taxable salary	Total remune-ration	Estimated pension cost 3)	Estimated present value of pension obligation
Lund Helge (CEO)	6,970	1,986	2,139	566	18	11,679	489	28	517	12,196	4,733	36,536
Reitan Torgrim (CFO)	2,798	588	527	245	43	4,201	62	16	78	4,279	583	10,989
Sjøblom Tove Stuhr (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 recident in Norway.

Statement on remuneration and other employment terms for Statoil's corporate executive committee

Pursuant to the Norwegian Public Limited Liability Companies Act § 6-16 a), the board will present the following statement regarding remuneration of Statoil's corporate executive committee to the 2012 annual general meeting:

1. Remuneration policy and concept for the accounting year 2011

1.1 Policy and principles

In general the company's established remuneration principles and general concepts will be continued in the accounting year 2012. 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.

1.2 The decision-making process

The decision-making process for implementing or changing remuneration policies and concepts, and the determination of salaries and other remuneration for corporate executive committee, are in accordance with the provisions of the Norwegian Public Limited Liability Companies Act paragraphs 5-6, 6-16 a) and the board's Rules of Procedures last amended 9 December 2010.

The board of directors has appointed a separate compensation committee. The compensation committee is a preparatory body for the board. The committee's main objective is to assist the board of directors in its work relating to the terms of employment for Statoil's chief executive officer and the main principles and strategy for the remuneration and leadership development of senior executives in Statoil. The board of directors determines the salary and other terms of employment for the chief executive officer.

1.3 The remuneration concept for the corporate executive committee

Statoil's remuneration concept for the corporate executive committee consists of the following main elements:

- Fixed remuneration
- Variable pay
- Pensions and insurance schemes
- Severance schemes
- Other benefits

An evaluation of changes to the company's general pension system, including the executive pension scheme has been started. Deviations from the general principles outlined below pertaining to two members of the corporate executive committee implemented with effect as of 1 January 2011 are described in section 2 below. These deviations were also described in the Statement on remuneration and other employment terms for Statoil's corporate executive committee for the accounting year 2010.

Fixed Remuneration

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

Base salary

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

Long Term Incentive (LTI)

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

The long-term incentive system is a fixed, monetary compensation calculated as a portion 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 both on short- and long-term goals and results. By ensuring that our top executives are holders of company shares, the long-term incentive contributes to the strengthening of 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 scheme and the size of the annual LTI element are reflective of the level and impact of the position and not directly linked to the incumbent's performance.

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

The performance evaluation is a holistic evaluation combining measurement and assessment of performance against both delivery and behaviour goals. The KPIs are used as *indicators* only. Hence, sound judgement and hindsight information 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 viewed to significantly reduce the likelihood that remuneration policies may stimulate excessive risk-taking or have other material adverse effects.

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

Pension and insurance schemes

Statoil ASA's current general pension plan is a defined benefit arrangement with a pension level amounting to 66% of the pensionable salary conditional on a minimum of 30 years of service. Pension from the National Insurance Scheme is taken into account when estimating the pension. The general retirement age is 67 for employees onshore and 65 for offshore employees.

The pension schemes for members of the corporate executive committee including the chief executive officer are supplementary agreements to the company's general pension plan.

Subject to specific terms in his pension agreement of 7 March 2004, the chief executive officer is entitled to a pension amounting to 66% of pensionable salary and a retirement age of 62. The full service period is 15 years.

Two of the executive vice presidents have individual pension terms according to a previous standard arrangement implemented in October 2006. Subject to specific terms those executives are entitled to a pension amounting to 66% of pensionable salary and a retirement age of 62. When calculating the number of years of membership in the Statoil ASA's general pension plan, these agreements grant the right to an extra contribution time corresponding to half a year of extra membership for each year the individual has served as executive vice president.

Under specific terms, one of the executive vice presidents is entitled to a pension amounting to 66% of pensionable salary and a retirement age of 62.

In addition, four of Statoil's executive vice presidents have an individually agreed retirement age of 65 and an early retirement pension level amounting to 66 % of pensionable salary.

The individual pension terms for executive vice presidents outlined above are results of commitments according to previous established agreements.

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

In addition to the pension benefits outlined above, the executive vice presidents in the parent company are offered other benefits in accordance with Statoil's general pension plan including pension from the age of 67 based on the defined benefit arrangement. Members of the corporate executive committee are covered by the general insurance schemes applicable within Statoil.

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

Statoil is currently in the process of evaluating changes to the general pension scheme in the parent company. This evaluation includes an assessment on the question of replacing the current defined benefit scheme with a defined contribution plan and the prevailing pension scheme for salaries exceeding 12 times the national insurance basic amount (G). This project is planned to conclude after the passage of the Banking Law Commission's recommendations in the parliament.

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

Severance schemes

Under the terms of his contract of 7 March 2004, the chief executive officer is entitled to severance payment corresponding to 24 months of base salary in the event of a board resolution to release him from his contract of employment. Severance payment is calculated from the expiry of the notice period of 6 months. The same entitlement applies should the parties agree that the employment will be discontinued and the chief executive officer gives notice pursuant to a written agreement with the board.

Executive vice presidents are entitled to a severance payment equivalent to six months' salary, commencing at the time of expiry of a six months' notice period, when the resignation is at the request from the company. The same amount of severance payment is also payable if the parties agree that the employment should be discontinued and the executive vice president gives notice pursuant to a written agreement with the company. Any other payment earned by the executive vice president during the period of severance payment will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

According to a previous agreement, one of the executive vice presidents is entitled to 18 months of severance payment, commencing at the time of expiry of a six months' notice period, provided the resignation is at the request of the company.

The entitlement to severance payment is conditional on the chief executive officer or the executive vice president not being guilty of gross misconduct, gross negligence, disloyalty or other material breach of his/her duties.

As a general rule, the chief executive officer's/executive vice president's own notice will not instigate any severance payment.

Other benefits

Statoil has a share savings plan available to all employees including members of the corporate executive committee. The Share savings plan entails an offer to purchase Statoil shares in the market limited to 5% of annual gross salary. If the shares are kept for two full calendar years of continued employment the employees will be allocated bonus shares proportionate to their purchase. Shares to be used for sale and transfer to employees are acquired by Statoil in the market, in accordance with the authorisation from the annual general meeting.

The members of the corporate executive committee have benefits in kind such as company car and free electronic communication.

2. Execution of the remuneration policy and principles in 2011

Deviations from the Statement on Executive remuneration 2011

Two members of the executive committee have variable pay schemes deviating from the description above. The individuals in question are employed by Statoil Gulf Services LLC in Houston and Statoil Global Employment Company Ltd. in London. These schemes entail a framework for variable pay of 75% to 100% of the base salary for each of the elements (annual variable pay and long-term incentive). The long-term incentive is performance based. The contracts also include a provision for severance payment of 12 months' base salary.

The board's overall assessment is that the extended framework implemented with effect from 1 January 2011 for the variable pay schemes for these executives is in alignment with the market for positions at this level at the respective locations.

3. Concluding remarks

Statoil's remuneration policy and solutions are aligned with the company's overall people policy and are integrated with the company's value and performance-oriented framework. Furthermore, the remuneration systems and practice are transparent and in accordance with prevailing guidelines and good corporate governance.

6 Share-based compensation

Statoil's share saving plan provides employees with the option to purchase Statoil shares through monthly salary deductions, and a contribution by Statoil ASA. 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 400 million and NOK 387 million related to 2011 and 2010, respectively. For the 2012 program (granted in 2011) the estimated compensation expense is NOK 460 million. At 31 December 2011 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 906 million.

7 Auditor's remuneration

(in NOK million, excluding VAT)	For the year ended 31 December 2011	2010
Audit fees	17.8	17.0
Audit related fees	3.3	10.6
Other service fees	0.0	0.1
Total	21.1	27.7

8 Research and development expenditures

Research and development expenditures were NOK 111 million and NOK 127 million in 2011 and 2010, respectively.

9 Financial items

(In NOK million)	For the year ended 31 December 2011	2010
Foreign exchange gains (losses) derivative financial instruments	1,601	(1,736)
Foreign exchange gains (losses) taxes payable	24	(473)
Other foreign exchange gains (losses)	2,208	(344)
Net foreign exchange gains (losses)	3,833	(2,553)
Dividends received	26	13
Gains (losses) financial investments	(958)	(94)
Interest income from group companies	3,149	1,699
Interest income and other financial income	1,204	3,059
Interest income and other financial items	3,421	4,677
Interest expense to group companies	(1,888)	(870)
Interest expense non-current financial liabilities	(2,092)	(2,148)
Interest expense current financial liabilities and other finance expenses	(879)	207
Interest and other finance expenses	(4,859)	(2,811)
Net financial items	2,395	(687)

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 Statement of income. Correspondingly, strengthening of USD versus NOK for the year ended 31 December 2010 resulted in fair value losses.

Included in Interest income and other financial income in 2010 is a gain of NOK 1.9 billion related to the initial public offering of Statoil Fuel and Retail ASA.

Interest expense current financial liabilities and other financial expenses include impairment of receivables on a subsidiary in 2011 of NOK 1.1 billion. This is partly offset by fair value changes on interest rate derivatives posted at fair value. Decreasing USD interest rates for the year ended 31 December 2011 and for the year ended 31 December 2010 resulted in reversed losses on these positions.

10 Income taxes

Income tax expense

(In NOK million)	For the year ended 31 December 2011	2010
Current taxes payable	774	(1,185)
Change in deferred tax	(798)	(1,406)
Income tax expense	(24)	(2,591)

Reconciliation of Norwegian nominal statutory tax rate to effective tax rate

(In NOK million)	For the year ended 31 December 2011	2010
Income before tax	68,329	35,138
Nominal tax rate 28%	19,132	9,840
Tax effect of:		
Permanent differences caused by USD as functional currency	(1,095)	(724)
Other permanent differences	(18,156)	(11,601)
Income tax prior years	(37)	(18)
Other	132	(88)
Total	(24)	(2,591)
Effective tax rate (%)	(0.04)	(7.37)

Significant components of deferred tax assets and liabilities were as follows:

(In NOK million)	At 31 December 2011	2010
Deferred tax assets on		
Inventory	6	7
Other current items	929	1,396
Tax losses carry forward	0	924
Pensions	5,415	3,689
Property, plant and equipment	0	917
Long term provisions	1,383	0
Other non-current items	97	107
Total deferred tax assets	7,830	7,040
Deferred tax liabilities on		
Property, plant and equipment	293	0
Other non-current items	961	3,062
Total deferred tax liabilities	1,254	3,062
Net deferred tax assets / (liabilities)	6,576	3,978

At 31 December 2011, Statoil ASA had recognised net deferred tax assets of NOK 6.6 billion, as it is considered probable that taxable profit will be available to utilise the deferred tax assets.

The movement in deferred income tax

(in NOK million)	2011	2010
Deferred income tax assets / (liabilities) at 1 January	3,978	2,722
Charged to the income statement	797	1,408
Other comprehensive income and other	1,801	(152)
Deferred income tax assets / (liabilities) at 31 December	6,576	3,978

11 Property, plant and equipment

(in NOK million)	Machinery, equipment and transportation equipment	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2010	2,535	976	1,192	3,880	160	8,743
Additions and transfers	631	0	253	0	88	972
Disposals assets at cost	(365)	(14)	0	0	0	(379)
Effect of movements in foreign exchange - assets	97	22	9	90	14	232
Cost at 31 December 2011	2,898	984	1,454	3,970	262	9,568
Accumulated depreciation and impairment losses at 31 December 2010	(1,609)	(870)	(293)	(875)	0	(3,647)
Depreciation and net impairment losses for the year	(509)	(10)	(54)	(188)	0	(761)
Accumulated depreciation and impairment disposed assets	363	11	0	0	0	374
Effect of movements in foreign exchange – depreciation and impairment losses	(65)	(21)	(11)	(33)	0	(130)
Accumulated depreciation and impairment losses at 31 December 2011	(1,820)	(890)	(358)	(1,096)	0	(4,164)
Carrying amount at 31 December 2011	1,078	94	1,096	2,874	262	5,404
Estimated useful lives (years)	3 - 10	15-20	20 - 33	20 - 25		

The book value of vessels consists of financial leases; for more information about financial lease see note 23 *Leases*.

12 Investments in subsidiaries and other equity accounted companies

(in NOK million)	
Investments at 1 January 2011	267,687
Net income from subsidiaries and other equity accounted companies	66,408
Additional paid-in equity	6,448
Pension adjustments	(309)
Distributions	(50,683)
Translation adjustments	4,937
Investments at 31 December 2011	294,488

The closing balance of NOK 294,488 million consists of investments in subsidiaries amounting to NOK 294,104 million and investments in other equity accounted companies amounting to NOK 384 million. In 2010, the amounts were NOK 267,321 million and NOK 366 million respectively.

Amortisation of goodwill amounts to NOK 458 million in 2011.

Distributions during 2011 mainly consists of a group contribution from Statoil Petroleum AS of NOK 49 billion.

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

13 Financial assets

Non-current prepayments and financial receivables

(in NOK million)	At 31 December 2011	2010
Financial receivables	1,032	645
Prepayments	268	280
Prepayments and financial receivables	1,300	925

Prepayments and financial receivables at 31 December 2011 and 2010 mainly consist of financing of the associated company European CO2 Technology.

Non-current financial receivables from subsidiaries and other equity accounted companies

(in NOK million)	At 31 December 2011	2010
Interest bearing receivables from subsidiaries and other equity accounted companies	66,440	83,061
Non-interest bearing receivables from subsidiaries	3,705	5,960
Receivables from subsidiaries and other equity accounted companies	70,145	89,021

Interest bearing receivables from subsidiaries and other equity accounted companies at 31 December 2011 are due later than five years, except from NOK 1.3 billion which is due within the next five years. Of the Non-interest bearing receivables from subsidiaries at 31 December 2011 NOK 3.5 billion relates to pension, see note 19 *Pension and other non-current employee benefits*. Correspondingly, NOK 4.7 billion related to pension at 31 December 2010. In 2011 an impairment of NOK 1.1 billion of Non-interest bearing receivables from subsidiaries has been posted towards Interest expense current financial liabilities and other financial expenses , see note 9 *Financial items*.

Current financial investments

(in NOK million)	At 31 December 2011	2010
Commercial papers	8,113	3,671
Money market funds	6,507	1,559
Financial investments	14,620	5,230

Current financial investments at 31 December 2011 and 2010 are considered to be trading securities, measured at fair value with gains and losses recognised in the Statement of income. The cost price for current financial investments at 31 December 2011 and 2010 was NOK 14.7 billion and NOK 5.3 billion, respectively.

14 Inventories

Inventories are valued at the lower of cost and net realisable value. Inventory of crude oil, refined products and non-petroleum products are determined under the first-in, first-out (FIFO) method.

(in NOK million)	At 31 December 2011	2010
Crude oil	7,422	11,086
Petroleum products	4,364	3,454
Other	1,382	481
Inventories	13,168	15,021

15 Trade and other receivables

(in NOK million)	At 31 December 2011	2010
Trade receivables	47,693	41,296
Other receivables	5,333	3,925
Trade and other receivables	53,026	45,221

16 Cash and cash equivalents

(in NOK million)	At 31 December 2011	2010
Cash at bank available	3,189	2,360
Time deposits	24,120	13,003
Restricted cash, including collateral deposits	799	2,768
Cash and cash equivalents	28,108	18,131

Restricted cash at 31 December 2011 include collateral deposits of NOK 0.8 billion related to trading activities, correspondingly collateral deposits at 31 December 2010 were NOK 2.8 billion. Collateral deposits are related to certain requirements set out by exchanges where the company is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

17 Equity and shareholders

Change in equity

(in NOK million)	2011	2010
Shareholders' equity at 1 January	194,925	174,870
Net income	68,353	37,730
Actuarial gain employee retirement benefit plans	(5,164)	148
Foreign currency translation adjustments*	6,809	2,227
Ordinary dividend	(20,705)	(19,890)
Value of stock compensation plan	60	113
Treasury shares purchased	(89)	(108)
Other	0	(165)
Total equity at 31 December	244,189	194,925

* The accumulated foreign currency translation effect as of 31 December 2011 is NOK 6.2 billion. At 31 December 2010 the corresponding effect was negative of NOK 0.6 billion.

Common stock

	Number of shares	Par value	Common stock
Authorised and issued	3,188,647,103	2.50	7,971,617,757.50
Treasury shares	7,931,347	2.50	19,828,367.50
Total outstanding shares	3,180,715,756	2.50	7,951,789,390.00

There is only one class of shares and all shares have voting rights.

The board of directors is authorised on behalf of the company to acquire Statoil shares in the market. The authorisation may be used to acquire Statoil shares with an overall nominal value of up to NOK 20 million. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the Statoil group as part of the group's share saving plan approved by the board. 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.

The 20 largest shareholders at 31 December 2011 (in %)		
1	The Norwegian State (Ministry of Petroleum and Energy)	67,00
2	Folketrygdfondet (Norwegian national insurance fund)	3,41
3	Bank of New York ADR Departement*	2,56
4	Clearstream Banking S.A*	1,90
5	State Street Bank*	1,16
6	State Street Bank*	1,01
7	The Northern Trust	0,78
8	State Street Bank*	0,78
9	Bank of New York Mellon*	0,77
10	Bank of New York Mellon Depositary Receipts	0,56
11	State Street Bank*	0,55
12	JPMorgan Chase Bank	0,53
13	JPMorgan Chase Bank	0,43
14	Six Sis AG	0,33
15	The Northern Trust	0,31
16	Danske bank operations	0,31
17	Six Sis AG	0,30
18	Bank of New York Mellon*	0,29
19	The Northern Trust	0,26
20	Euroclear Bank	0,26

* Client account and similar

Members of the board of directors, corporate executive committee and corporate assembly holding shares as of 31 December 2011:

Board of directors	
Svein Rennemo	10,000
Marit Arnstad	0
Grace Reksten Skaugen	400
Bjørn Tore Godal	0
Lady Barbara Judge	2,488
Jakob Stausholm	2,600
Roy Franklin	0
Lill-Heidi Bakkerud	330
Morten Svaan	2,235
Einar Arne Iversen	3,462

Corporate executive committee	
Helge Lund	41,647
Torgrim Reitan	12,094
Margareth Øvrum	21,309
Eldar Sætre	17,129
Tove Stuhr Sjøblom	5,540
Peter Mellbye	20,977
Øystein Michelsen	14,205
Tim Dodson	11,528
William Maloney	4,516
John Knight	27,967
Corporate assembly (in total)	11,875

18 Bonds, bank loans and finance lease liabilities

(in NOK million)	At 31 December 2011	2010
Unsecured bonds	94,498	84,787
Unsecured loans	5,117	4,945
Financial lease liabilites	3,246	3,307
Gross financial liabilities	102,861	93,039
Less current portion	3,336	2,738
Bonds, bank loans and finance lease liabilities	99,525	90,301
Weighted average interest rate (%)	4.55	5.04

Statoil utilises currency swaps to manage foreign exchange risk on its non-current financial liabilities. Long-term currency swaps are reflected in the table above. The stated interest rate on the majority of the non-current loans are fixed. Interest rate swaps are utilised to manage interest rate exposure.

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 23 *Leases*.

Details of largest unsecured bonds:

Bond agreement	Fixed interest rate	Issued (year)	Maturity (year)	Carrying amount in NOK million at 31 December 2011	2010
USD 1500 million	5.250 %	2009	2019	8,947	8,738
USD 1250 million	3.125 %	2010	2017	7,454	7,278
USD 900 million	2.900 %	2009	2014	5,378	5,251
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
USD 500 million	3.875 %	2009	2014	2,986	2,914
USD 500 million	6.500 %	1998	2028	2,969	2,900
USD 481 million	7.250 %	2000	2027	2,880	2,814
USD 350 million	4.250 %	2011	2041	2,079	-
EUR 1300 million	4.375 %	2009	2015	10,064	10,135
EUR 1200 million	5.625 %	2009	2021	9,235	9,297
GBP 800 million	6.875 %	2009	2031	7,397	7,224
GBP 225 million	6.125 %	1998	2028	2,098	2,040

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 bond holders and lenders.

Statoil has 30 unsecured bond agreements outstanding, which contain provisions allowing Statoil to call the debt prior to its final redemption at par or at certain specified premiums if there are changes to the Norwegian tax laws. The carrying amount of these agreements is NOK 91.7 billion at 31 December 2011 closing rate.

Non-current financial liabilities repayment profile

(in NOK million)	
2013	2,923
2014	12,275
2015	11,836
2016	6,669
Thereafter	65,822
Total	99,525

Statoil ASA has an undrawn revolving credit facility for USD 3.0 billion supported by 20 core banks.

19 Pensions and other non-current employee benefits

Pension obligation

Statoil ASA (Statoil) is obligated to follow the Mandatory Company Pensions Act and the company's pension scheme follows the requirements of the Act.

Statoil's pension scheme is managed by Statoil Pensjon (Statoil's pension fund - hereafter "Statoil Pension"). Statoil Pension is an independent pension fund that covers employees of Statoil ASA. The purpose of Statoil Pension is to provide retirement and disability pension to members and survivor's pension to spouses, registered partners, cohabitants and children. The pension fund's assets are kept separate from the company's assets. Statoil Pension is supervised by the Financial Supervisory Authority of Norway ("Finanstilsynet") and is licensed to operate as a pension fund.

Statoil has defined benefit retirement plans which cover all of its employees.

The Norwegian Insurance Scheme ("Folketrygden") provides pension payments (social security) to all retired Norwegian citizens. Such payments are calculated by reference 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.

New legislation in Norway affecting the early retirement pension plans in the National Insurance Scheme came into force 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 for Statoil's payment portfolio for earned benefits.

Actuarial gains and losses are recorded directly in *Retained earnings* 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 the 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.

Net pension cost

(In NOK million)	For the year ended 31 December 2011	2010
Current service cost	3,419	3,308
Interest cost	2,538	2,562
Expected return on plan assets	(2,681)	(2,489)
Actuarial (gain)/loss related to termination benefits	57	200
Defined benefit plans	3,333	3,581
Multi-employer plans	83	161
Total net pension cost	3,416	3,742

Pension cost includes associated social security tax.

Pension cost is partly charged to partners of Statoil operated licenses.

For information regarding pension benefits for management, reference is made to note 5 *Remuneration*.

Change in projected benefit obligation (PBO)

(in NOK million)	2011	2010
Projected benefit obligation at 1 January	59,285	52,256
Current service cost	3,419	3,308
Interest cost	2,538	2,562
Actuarial loss (gain)	2,488	1,988
Benefits paid	(1,608)	(1,697)
Acquisition and sale	0	(314)
Change in receivable from subsidiary related to termination benefits	1,189	1,182
Projected benefit obligation at 31 December	67,311	59,285

Change in pension plan assets

(in NOK million)	2011	2010
Fair value of plan assets at 1 January	47,610	40,154
Expected return on plan assets	2,681	2,489
Actuarial gain (loss)	(4,252)	1,599
Company contributions (including social security tax)	3,132	3,900
Benefits paid	(431)	(425)
Acquisition and sale	0	(107)
Fair value of plan assets at 31 December	48,740	47,610

The tables above for Change in projected benefit obligation (PBO) and Change in pension plan assets do not include currency effects. For more information see the table Actuarial gains and losses recognised directly in retained earnings below.

Changes in net pension liablity

(in NOK million)	2011	2010
Balance sheet provision at 1 January	(11,676)	(12,101)
Net periodic pension costs defined benefit plans	(3,333)	(3,581)
Net actuarial gain (loss) recognised in retain earnings*	(6,717)	(91)
Less employer contributions	3,132	3,900
Less benefit paid during year	1,176	1,272
Acquisition and sale	0	206
Change in receivable from subsidiary related to termination benefits	(1,189)	(1,182)
Foreign currency translation and other changes	35	(99)
Balance sheet provision at 31 December	(18,572)	(11,676)

Net benefit liability at 31 December

(in NOK million)	2011	2010
Net benefit liability at 31 December	(18,572)	(11,676)
Represented by:		
Asset recognised as Non-current pension asset	3,865	5,087
Asset recognised as Non-current receivables from subsidiary**	3,545	4,734
Liability recognised as Non-current pension liability	(25,982)	(21,497)

** Asset recognised as Non-current receivables from subsidiary relates to termination benefits.

Projected benefit obligation specified by funded and unfunded plans

(in NOK million)	2011	2010
Funded pension plans	(44,874)	(42,522)
Unfunded pension plans	(22,437)	(16,764)
Projected benefit obligation (PBO) at 31 December	(67,311)	(59,286)

Actuarial gains and losses recognised directly in retained earnings

(in NOK million)	2011	2010
Unrecognised actuarial losses (gains) at 1 January	0	0
Actuarial losses (gains) on plan assets occur during the year	4,252	(1,599)
Actuarial losses (gains) on benefit obligation occur during the year	2,488	1,989
Actuarial losses (gains) related to currency effects on net obligation***	(220)	(245)
Recognised in the income statement during the year	(57)	(200)
Foreign exchange translation***	254	146
Recognised directly in retained earnings during the year*	(6,717)	(91)
Unrecognised actuarial losses (gains) at 31 December	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.
*** Actuarial losses (gains) related to currency effects on net obligation relate to the translation of the net obligation in NOK to the functional currency USD. The line item Foreign exchange translation relates to the translation of the net pension obligation from the functional currency of USD to presentation currency of NOK.

Actual return on plan assets

(in NOK million)	For the year ended 31 December 2011	2010
Actual return on plan assets	(1,571)	4,088

History of experience gains and losses

(in NOK million)	2011	2010
Fair value of plan assets at 31 December	48,740	47,610
Projected benefit obligation included receivable related to termination benefits	67,311	59,286
Receivable from subsidiary related to termination benefits	3,545	4,734
Projected benefit obligation at 31 Desember	70,856	64,020
Difference between the expected and actual return on plan assets		
a) Amount	4,252	(1,599)
b) Percentage of plan assets	8.72%	(3.36%)
Experience (gains)/losses on plan liabilities		
a) Amount	2,827	(91)
b) Percentage of present value of plan liabilities	3.99%	(0.00%)

The cumulative amount of actuarial gains and losses recognised directly to equity amounted to NOK 15.2 and NOK 10.3 billion net of tax with a negative effect on equity in 2011 and 2010, respectively.

Assumptions used to determine benefit cost for the year ended 31 December 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

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.

	Disability in %		Mortality in %		Expected lifetime	
Age	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.

	Discount rate		Rate of compensation increase		Social security base amount		Expected rate o f pension increase	
(in NOK billion)	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%	0.50%	-0.50%
Changes in:								
Projected benefit obligation								
at 31 December 2011	(7.14)	7.32	4.35	(4.26)	(0.05)	0.16	4.07	(4.02)
Service cost 2012	(0.57)	0.59	0.39	(0.38)	(0.01)	0.00	0.32	(0.31)

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 financial statements because the 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 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 Norwegian Government bond with a life of 10 year has been extrapolated by use of a yield curve from another currency with long observable interest rates) is applied as a starting point for calculation of return on plan assets. The expected return on money market 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 money market.

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 regulation 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 1.9 billion 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 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.

20 Provisions and other liabilities

(in NOK million)	Provisions	Other liabilities	Total
Non-current portion at 31 December 2010	33	1,069	1,102
Current portion at 31 December 2010 reported as trade and other payables	1,074	0	1,074
Provisions and other liabilities at 31 December 2010	1,107	1,069	2,176
New provisions in the period	25	1	26
Revision in the estimates	894	85	979
Amounts charged against provisions	(229)	0	(229)
Reclassification and transfer	0	32	32
Currency translation	84	48	132
Provisions and other liabilities at 31 December 2011	1,881	1,235	3,116
Current portion at 31 December 2011 reported as trade and other payables	1,857	0	1,857
Long term interest bearing provision reported as bonds, bank loans and finance lease liabilities	24	0	24
Non-current portion at 31 December 2011	0	1,235	1,235

21 Trade and other payables

(in NOK million)	At 31 December 2011	2010
Trade payables	20,004	13,827
Non-trade payables, accrued expenses and provisions	8,913	8,844
Payables to associated companies and other related parties	10,634	9,458
Trade and other payables	39,551	32,129

22 Bonds, bank loans, commercial papers and collateral liabilities

(in NOK million)	At 31 December 2011	2010
Bank loans and overdraft facilities	0	32
Collateral liabilities	10,843	5,680
Current portion of bonds and bank loans	3,107	2,541
Current portion of finance lease	229	197
Bonds, bank loans, commercial papers and collateral liabilities	14,179	8,450
Weighted average interest rate (%)	1.22	1.94

Collateral liabilities relate to cash received as security for a portion of Statoil ASA's credit exposure.

As of 31 December 2011 and 2010, Statoil had no current amount drawn under any committed revolving credit facility.

23 Leases

Statoil ASA leases certain assets, notably vessels and office buildings.

In 2010 Statoil ASA entered into a long term time charter agreement with Teekay for offshore loading and transport in the North Sea. The contract covers the life time of applicable producing fields and at year end 2011 includes six crude tankers. The contract's estimated nominal amount is approximately NOK 5.8 billion at year end 2011, and is accounted for as operating lease. The estimated future leasing commitment depends on assumptions made concerning field production quantities and related lifetime, expected decrease in the number of vessels employed over time, as well as development in other factors impacting Statoil ASA's payable amounts under the terms of the contract.

Statoil ASA leases three LNG vessels on behalf of Statoil and the State's direct financial interest (SDFI). Statoil ASA accounts for the combined Statoil and SDFI share of these agreements as finance leases in the Balance sheet, and further accounts for the SDFI related portion as operating sub-leases. 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.

In 2011, net rental expense was NOK 1.9 billion (NOK 1.7 billion in 2010) of which minimum lease payments were NOK 1.9 billion (NOK 1.7 billion in 2010). Contingent rents expensed and sublease amounts received were immaterial both years.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2011. Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year-end 2011.

			Finance leases		
(in NOK million)	Operating leases	Operating sublease	Minimum lease payments	Discount element	Net present value minimum lease payments
2012	2,272	(156)	315	(14)	301
2013	1,715	(156)	315	(27)	288
2014	1,515	(156)	315	(39)	276
2015	1,472	(156)	315	(51)	264
2016	1,235	(156)	315	(62)	253
Thereafter	7,916	(1,404)	2,836	(997)	1,839
Total future minimum lease payments	16,125	(2,184)	4,411	(1,190)	3,221

The column Operating sublease includes future operating lease payments from the SDFI related to the three above-mentioned LNG vessels. As of 2011, Operating leases include future minimum lease payments of NOK 4.7 billion related to the lease of two office buildings located in Bergen and owned by Statoil Pension, one of which is currently under construction. These 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 include the following amounts for leases that have been capitalised at 31 December 2011 and 2010.

	At 31 December	
(in NOK million)	2011	2010
Vessels	3,970	3,880
Accumulated depreciation	(1,096)	(875)
Capitalised amount	2,874	3,005

24 Other commitments and contingencies

Long-term commitments

Statoil ASA 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 company the obligation to pay for the agreed-upon service or commodity, irrespective of actual use. The contracts' terms vary, with duration of up to 30 years.

Take-or-pay contracts for the purchase of commodity quantities are only included in the table below if their contractually agreed pricing is of a nature that will or may deviate from the obtainable market prices for the commodity at the time of delivery.

Obligations payable by Statoil ASA to entities accounted for using the equity method are included gross in the tables below. For assets (e.g. pipelines) that the company accounts for by recognising its share of assets, liabilities, income and expenses (capacity costs) on a line-by-line basis in the financial statements, the amounts in the table include the net commitment payable by Statoil ASA (i.e. gross commitment less Statoil's ownership share).

Nominal minimum commitments at 31 December 2011:

(in NOK million)	
2012	9,329
2013	9,088
2014	8,919
2015	9,447
2016	9,902
Thereafter	74,641
Total	121,326

The above table outlines nominal minimum obligations for future years, and mainly includes commitments related to the Statoil group's natural gas operations in addition to various other transport and similar commitments.

Statoil ASA has entered into pipeline transportation agreements for most of its prospective gas sales contracts. The main transportation commitments are Statoil ASA's booked capacity in Gassled. Statoil ASA however has corresponding firm commitments to provide its fully owned subsidiary Statoil Petroleum AS with this capacity. Following the Statoil group's sale of a 24.1% ownership share in Gassled during 2011, Statoil Petroleum AS retains a 5% ownership interest at year end 2011. The above table of Statoil ASA's commitments includes the company's Gassled capacity bookings gross, so that neither capacity related to the group's remaining 5% ownership interest nor firmly committed group internal capacity transfers have been netted in the table's amounts. These matters however significantly decrease the stand-alone risk for Statoil ASA in firmly committing to long term Gassled bookings.

Guarantees

Statoil ASA has provided parent company guarantees covering liabilities of subsidiaries with operations in Algeria, Angola, Azerbaijan, Belgium, Brazil, Canada, Cuba, the Faroe Islands, Germany, India, Iran, Iraq, Ireland, Libya, Mozambique, the Netherlands, Nigeria, Norway, Russia, Sweden, United Kingdom, the United States of America and Venezuela. The company has also counter-guaranteed certain bank guarantees covering liabilities of subsidiaries in Angola, Belgium, Brazil, Canada, Cuba, Denmark, Egypt, Indonesia, Iran, Ireland, Mozambique, the Netherlands, Norway, Switzerland, United Kingdom and the United States of Amercia.

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 its carrying value is immaterial.

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 ASA is jointly liable for is approximately NOK 1.0 billion. As of the current date, the probability that these guarantee commitments will impact Statoil ASA is deemed to be remote. No liability has been recognised in the financial statements at year end 2011.

Other commitments and contingencies

Statoil ASA is the participant in certain entities ("DAs") in which the company has unlimited responsibility for its proportionate share of such entities' liabilities, if any, and also participates in certain companies ("ANSs") in which the participants in addition have joint and several liability. For further details, refer to note 12 *Investments in subsidiaries and other equity accounted investments*.

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 financial Statement of income.

During the normal course of its business Statoil ASA 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 ASA has provided in its financial statements for probable liabilities related to litigation and claims based on the company's best judgement. Statoil ASA does not expect that its financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

25 Related parties

The Norwegian State is the majority shareholder of Statoil ASA and also holds major investments in other Norwegian companies. This ownership structure means that Statoil ASA 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 ASA 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 *Revenue*, 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 ASA's financial statements. 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) and NOK 81.4 billion (176 million barrels oil equivalents) in 2011 and 2010, respectively. Purchases of natural gas regarding Tjelbergodden methanol plant from the Norwegian State amounted to NOK 0.4 billion and NOK 0.4 billion in 2011 and 2010, respectively. The major part included in the line item Payables to equity accounted investments and other related parties in note 21 *Trade and other payables*, are amounts payable to the Norwegian State for these purchases.

In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, Statoil ASA also has regular transactions with certain entities in which Statoil ASA has ownership interests. Such transactions are carried out on an arm's length basis, and are included within the applicable captions in the Statements of income.

Stavanger, 13 March 2012

THE BOARD OF DIRECTORS OF STATOIL ASA

Svein Rennemo

SVEIN RENNEMO
CHAIR

Marit Arnstad
MARIT ARNSTAD
DEPUTY CHAIR

Lill-Heidi Bakkerud
LILL-HEIDI BAKKERUD

BJØRN TORE GODAL

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Lady Barbara Judge
LADY BARBARA JUDGE

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EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

Jakob Stausholm
JAKOB STAUSHOLM

Morten Svaan
MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

Report of Ernst & Young AS on the financial statements of Statoil ASA

AUDITOR'S REPORT

Report on the financial statements
We have audited the accompanying financial statements of Statoil ASA, comprising the financial statements for the Parent Company and the Group. The financial statements of the Parent Company comprise the balance sheet as at 31 December 2011, the statements of income and cash flows for the year then ended and a summary of significant accounting policies and other explanatory information. The financial statements of the Group comprise the consolidated balance sheet as at 31 December 2011, the consolidated statements of income, comprehensive income, cash flows and changes in equity for the year then ended as well as a summary of significant accounting policies and other explanatory information.

The Board of Directors' and Chief Executive Officer's responsibility for the financial statements
The Board of Directors and Chief Executive Officer are responsible for the preparation and fair presentation of these financial statements in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway for the financial statements of the Parent Company and the International Financial Reporting Standards as adopted by the EU for the Group, and for such internal control as the Board of Directors and Chief Executive Officer determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion on the financial statements for the Parent Company and the Group.

Opinion on the financial statements of the Parent Company
In our opinion, the financial statements of Statoil ASA have been prepared in accordance with laws and regulations and present fairly, in all material respects, the financial position of the Company as of 31 December 2011 and its financial performance and cash flows for the year then ended in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway.

Opinion on the financial statements of the Group
In our opinion, the financial statements of the Group have been prepared in accordance with laws and regulations and present fairly, in all material respects, the financial position of the Group as of 31 December 2011 and its financial performance and cash flows for the year then ended in accordance with the International Financial Reporting Standards as adopted by the EU.

Report on other legal and regulatory requirements

Opinion on the Board of Directors' report and the statement on corporate governance
Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Directors' report and the statement on corporate governance concerning the financial statements, the going concern assumption and the proposal for the allocation of the result is consistent with the financial statements and complies with the law and regulations.

Opinion on registration and documentation
Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, «Assurance Engagements Other than Audits or Reviews of Historical Financial Information», it is our opinion that the Board of Directors and Chief Executive Officer have fulfilled their duty to ensure that the Company's accounting information is properly recorded and documented as required by law and generally accepted bookkeeping practice in Norway.

Stavanger, 13 March 2012
Ernst & Young AS

Finn Kinserdal
State Authorised Public Accountant (Norway)

(This translation from Norwegian has been made for information purposes only.)

HSE accounting

We aim to ensure safe operations that safeguard people, the environment, communities and material assets. We will use natural resources efficiently, and will provide energy that supports sustainable development. We believe that accidents can be prevented.

A key element in our HSE management system is the recording, reporting and assessment of relevant data. HSE performance indicators have been established to provide information on historical trends. The intention is to document quantitative developments over time and to use the information in decision-making aimed at systematic learning and improvement.

Our HSE data is compiled by the business areas and reported to the corporate executive committee, which evaluates trends and decides on the required improvement measures at the corporate level. In addition, the business areas prepare more specific HSE statistics and analyses that are used in their own improvement efforts.

The corporate executive committee submits the HSE results and associated assessments to the board of directors together with the group's quarterly financial results. We communicate key results internally and externally. As a part of this, quarterly HSE statistics are made available in the performance report. HSE data from activities at all assets and projects in which Statoil is the operator are included. Among our group-wide performance indicators for HSE, the following were most closely followed up at group level in 2011:

- ***Serious incident frequency (SIF)*** - The number of serious incidents per million hours worked
- ***Technical safety condition (TTS)*** - Status, observations and actions
- ***Climate*** - Tonnes of carbon dioxide emitted per kilotonne of produced hydrocarbons

Several other performance indicators are being monitored. The key performance indicators are reported quarterly at the corporate level for Statoil employees and contractors. Statistics on our employees' sickness absence are reported annually at the corporate level.

Historical data include figures relating to acquired operations from the acquisition date. Correspondingly, figures relating to divested operations are included up to the divestment date.

Results

The HSE accounting shows the development of the HSE performance indicators over the past five years.

During 2011, our operations account for 142 million working hours (including contractors). These working hours form the basis for the frequency indicators in the HSE accounting. Contractors handle a significant proportion of the assignments that Statoil is responsible for as the operator or principal enterprise.

Statoil's HSE results with regard to serious incidents have shown a positive improvement over the past four years. The overall serious incident frequency (SIF) indicator decreased from 2010 (1.4) to 2011 (1.1). When excluding the Fuel & Retail (SFR) segment, SIF was 0.9 in 2011, compared with 1.3 in 2010.

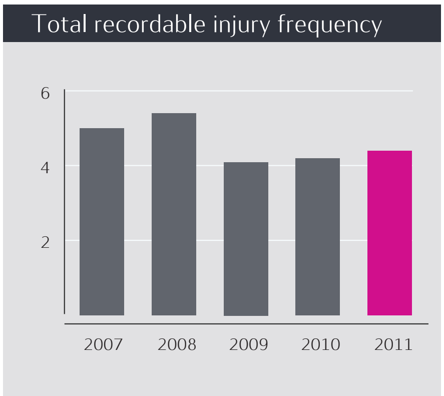
There was one fatality in 2011. A contractor employee performing maintenance work at service stations in Riga (Latvia) was killed in a traffic accident. In addition, on 6 October, a contractor employee was reported missing from the Visund platform in the North Sea. An extensive search operation, both at the platform, in the sea and on the seabed around the platform was unfortunately unsuccessful.

There has been an increase in the number of total recordable injuries per million working hours (TRIF) in 2011 (4.4) compared with 2010 (4.2). Contractor TRIF at year-end 2011 was 5.1, and Statoil employee TRIF was 3.3. The lost-time injury frequency (injuries leading to absence from work) was 1.9 in 2011, an increase from 2010 (1.8).

The number of accidental oil spills was 376 in 2011 compared with 374 in 2010. The volume was at the same level in 2010 and 2011 (44 cubic metres).

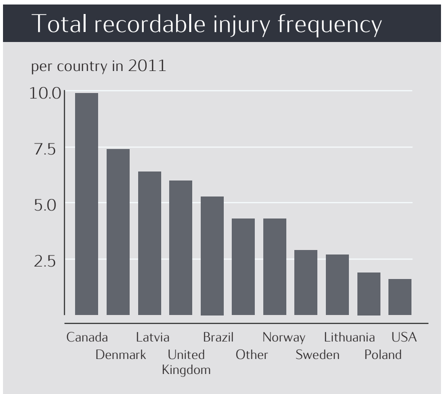
HSE performance indicators

These are the charts and statistics for our key HSE performance indicators.



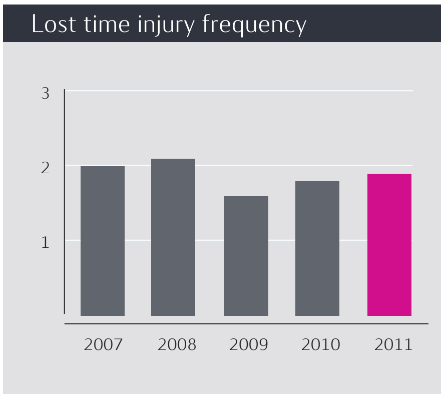
Definition: The number of fatalities, lost-time injuries, cases of substitute work and other injuries requiring treatment by a medical professional per million hours worked.

Developments: The total recordable injury frequency (including both Statoil employees and contractors) increased from 4.2 in 2010 to 4.4 in 2011. The frequency for Statoil employees was the same in 2011 as in 2010 (3.3), but the total recordable injury frequency for our contractors increased from 4.8 in 2010 to 5.1 in 2011.



The number of fatalities, lost-time injuries, cases of substitute work and other injuries requiring treatment by a medical professional per million hours worked shown per country in 2011 (1)

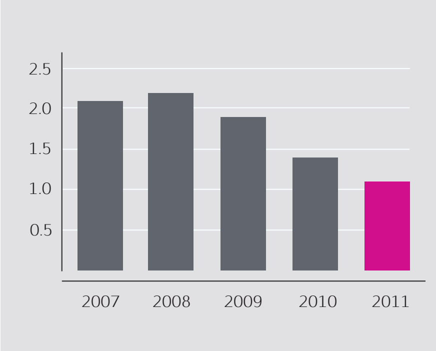
(1) Countries having less than 1 million work hours in 2011 are included in the category "Other"



Definition: The number of fatalities and lost-time injuries per million hours worked.

Developments: The lost-time injury frequency (including both Statoil employees and contractors) increased from 1.8 in 2010 to 1.9 in 2011. The frequency for Statoil employees decreased from 2.0 in 2010 to 1.9 in 2011, while the lost-time injury frequency for our contractors increased from 1.7 in 2010 to 1.9 in 2011.

Serious incident frequency

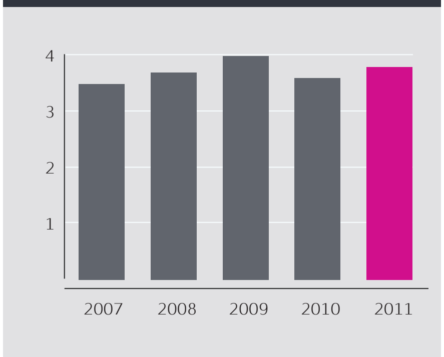


Definition: The number of serious incidents (including near misses) per million hours worked (2).

Developments: The serious incident frequency (including both Statoil employees and contractors) decreased from 1.4 in 2010 to 1.1 in 2011. There was one fatality in 2011. A contractor employee performing maintenance work at service stations in Riga (Latvia) was killed in a traffic accident.

(2) An incident is an event or chain of events that has caused or could have caused injury, illness and/or damage to/loss of property, the environment or a third party. Matrices for categorisation have been established in which all undesirable incidents are categorised according to the degree of seriousness. This forms the basis for follow-up in the form of notification, investigation, reporting, analysis, experience transfer and improvement.

Sickness absence

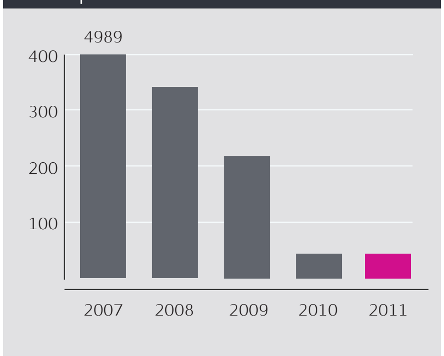


Definition: The total number of sickness absence hours as a percentage of planned working hours (Statoil employees) (3).

Developments: Sickness absence increased from 3.6% in 2010 to 3.8% in 2011. The increase is most significant in our Norwegian operations.

(3) In 2010 and 2011, Statoil calculated sickness absence as a percentage of planned working hours. Previous years' sickness absence was calculated as a percentage of planned working days.

Oil spills

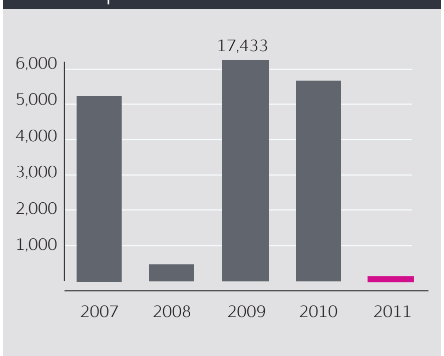


Definition: Unintentional oil spills to the natural environment from Statoil operations (in cubic metres) (4).

Developments: The number of unintentional oil spills was 376 in 2011, compared with 374 in 2010, and the volume in 2011 was the same as in 2010 (44 cubic metres).

(4) All unintentional oil spills reaching the natural environment from Statoil operations are included in the figure.

Other spills

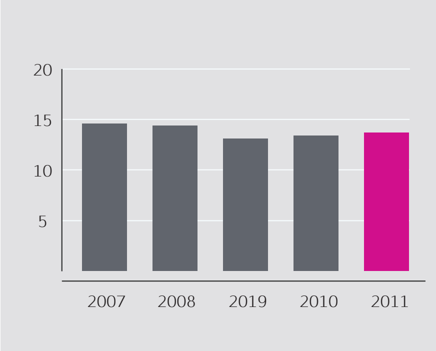


Definition: Other unintentional spills to the natural environment from Statoil operations (in cubic metres) (5).

Developments: The number of other unintentional spills was 146 in 2011, compared with 144 in 2010, and the volume in 2011 was 134 cubic metres compared with 5709 cubic metres in 2010.

(5) All unintentional spills of chemicals, produced water, ballast water and polluted water reaching the natural environment from Statoil operations are included. Figures at the corporate level from 2009 are verified by external auditors.

CO2 emissions

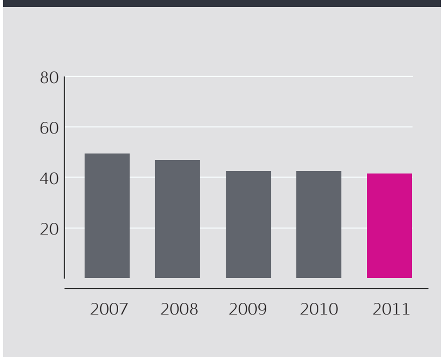


Definition: Total emissions of carbon dioxide (CO2) in million tonnes from Statoil operated activities (6)

Developments: Emissions of CO2 have increased slightly from 13.4 million tonnes in 2010 to 13.7 million tonnes in 2011. Emissions from our international operations have increased in 2011 due to increased activities, mainly Leismer (Canada) and Peregrino (Brazil). The emissions from our mid and downstream activities have increased, mainly due to the first year of ordinary operation of the combined heat and power plant at Mongstad. Emissions on the Norwegian continental shelf have decreased due to lower production. CO2 emissions from flaring have decreased from 1.3 million tonnes in 2010 to 1.2 million tonnes in 2011.

(6) Carbon dioxide emissions include carbon dioxide from energy and heat production, flaring (including well testing/well work-over), rest emissions from carbon dioxide capture and treatment plants and process emissions.

NOx emissions

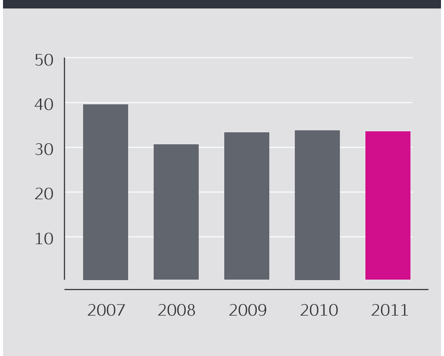


Definition: Total emissions of nitrogen oxides (NOx) in thousand tonnes from Statoil operated activities (7)

Developments: Emissions of NOx have decreased from 42.3 thousand tonnes in 2010 to 41.4 thousand tonnes in 2011.

(7) Nitrogen oxide emissions include nitrogen oxides from energy and heat production at our own plants, from the transportation of products, flaring (included well testing/well work-over) and treatment plants.

CH4 emissions

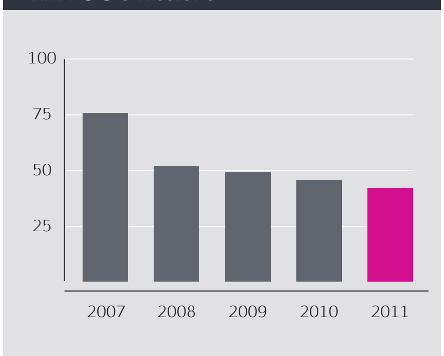


Definition: Total emissions of methane (CH4) in thousand tonnes from Statoil operated activities (8)

Developments: Methane emissions have decreased slightly from 33.4 thousand tonnes in 2010 to 33.1 thousand tonnes in 2011. Emissions from our international operations have increased due to increased activities, while emissions on the Norwegian continental shelf have decreased by 8.2 % from 2010 to 2011 due to lower production.

(8) CH4 emissions include CH4 from energy and heat production at own plants, flaring (included well testing/well work-over), cold venting, diffuse emissions and also storage and loading of crude oil. The correction in the 2010 data compared with last year's report is due to missing registration of data for Åsgard A and Åsgard B. Figures at the corporate level from 2009 are verified by external auditors.

nmVOC emissions

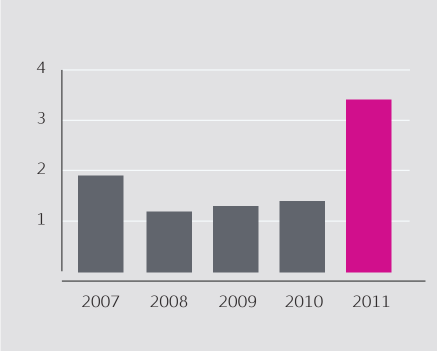


Definition: Total quantity of non-methane volatile organic compounds (nmVOC) in thousand tonnes released to the atmosphere from Statoil operated activities (9)

Developments: Emissions of nmVOC decreased from 45.4 thousand tonnes in 2010 to 41.6 thousand tonnes in 2011. The main reason for the reduced emissions is a 50% reduction in loaded volumes of oil from the Gullfaks A platform on the Norwegian continental shelf.

(9) Includes emissions of nmVOC from energy and heat production, transportation of products, flaring (including well testing/well work-over), cold venting, diffuse emission sources, storage and loading of crude oil and products, and also rest emissions from nmVOC recovery plant. Figures at the corporate level from 2011 are verified by external auditors.

SOx emissions

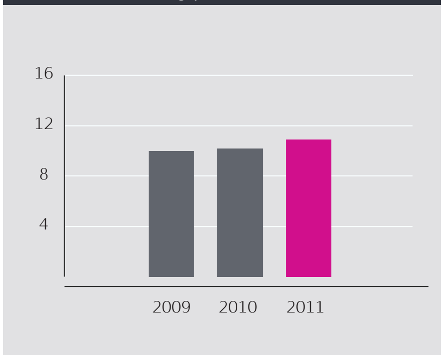


Definition: Total volume of sulphur oxides (SOx) in thousand tonnes released to the atmosphere from Statoil operated activities (10)

Developments: Emissions of sulphur oxides increased from 1.4 thousand tonnes in 2010 to 3.4 thousand tonnes in 2011. The main reason for the increase in SOx emissions is the start of production at the Peregrino field in Brazil, where diesel is currently used as an energy source.

(10) Includes emissions of SOx from energy and heat production and flaring (including well testing/well work-over). Figures at corporate level from 2011 are verified by external auditors.

Global warming potential (GWP)



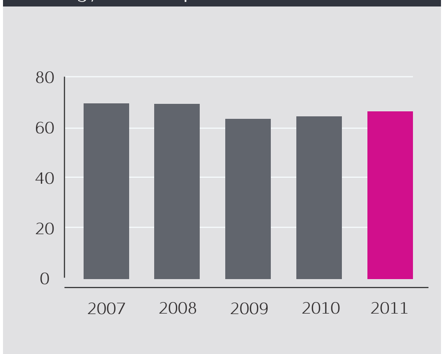
Definition: Global warming potential (GWP) is Statoil's share of greenhouse gas emissions from Statoil operated activities and activities operated by others (11)

Developments: GWP is reported on an equity share basis and has increased from 10.2 million tonnes in 2010 to 10.9 million tonnes in 2011. Equity share CO2 emissions have increased, but equity share methane emissions have decreased.

(11) The unit of measurement is "tonnes of carbon dioxide equivalent". This indicator is calculated based on Statoil's share of emissions of carbon dioxide and methane, using the following formula:

[1*(emissions of CO2)]+[21*(emissions of CH4)].

Energy consumption

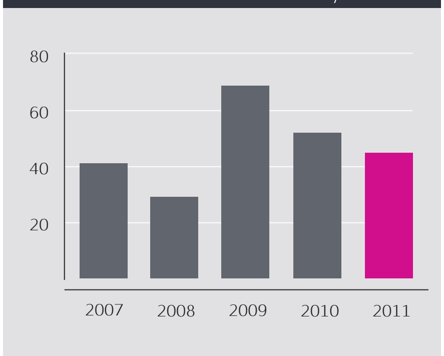


Definition: Total energy consumption in TWh for Statoil operated activities (12)

Developments: Total energy consumption has increased from 64.5 TWh in 2010 to 66.5 TWh in 2011. Energy consumption in our international operations has increased in 2011 due to increased activity, mainly from Leismer and Peregrino. The energy consumption at our land-based facilities has increased, while energy consumption on the Norwegian continental shelf has decreased due to lower production.

(12) Energy consumption includes energy from power and heat production based on combustion, unused energy from flaring (including well testing/well work-over and venting), energy sold/delivered to third parties and gross energy (heat and electricity) imported from contractors.

Non-hazardous waste recovery rate



Definition: The recovery rate for non-hazardous waste comprises non-hazardous waste from Statoil operated activities and represents the amount of non-hazardous waste for recovery as a proportion of the total quantity of non-hazardous waste (13)

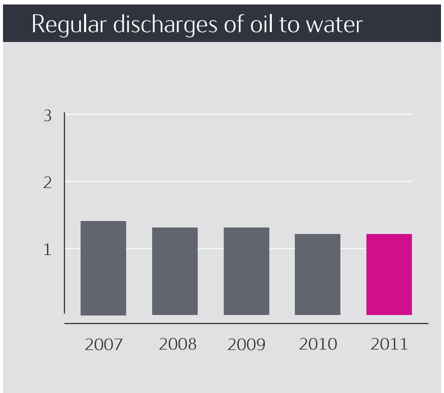
Developments: The non-hazardous waste recovery rate has decreased from 51.9% in 2010 to 44.8% in 2011.

(13) The quantity of non-hazardous waste for recovery is the total quantity of non-hazardous waste from the plant's operations that has been delivered for reuse, recycled or incinerated with energy recovery.

Definition: The hazardous waste recovery rate comprises hazardous waste from Statoil operated activities and represents the amount of hazardous waste for recovery as a proportion of the total quantity of hazardous waste (14)

Developments: The hazardous waste recovery rate has decreased from 28.7% in 2010 to 17.2% in 2011.

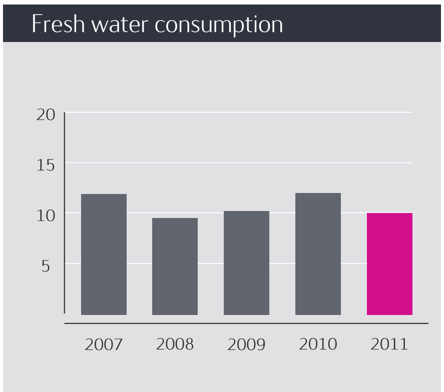
(14) The quantity of hazardous waste for recovery is the total quantity of hazardous waste from the plant's operations that has been delivered for reuse, recycled or incinerated with energy recovery (the total amount of hazardous waste, excluding hazardous waste sent to an approved deposition facility). The figures at the corporate level from 2009 are verified by external auditors.



Definition: Regular discharges of oil to water in thousand tonnes represent the total amount of oil via regulated or controlled discharges to water environment (both freshwater recipients and sea) from Statoil operated activities (15)

Developments: The amount of regular discharges of oil to water is at a stable level, and was the same in 2011 as in 2010 (1.2 thousand tonnes).

(15) Figures at the corporate level from 2011 are verified by external auditors.



Definition: The total consumption of fresh water, including water from public installations, wells (included reservoirs), lakes, streams, rivers and fresh water that is bought from Statoil operated activities in million cubic metres (16)

Developments: The fresh water consumption has decreased from 12.1 million cubic metres in 2010 to 10.1 million cubic metres in 2011.

(16) Fresh water produced from salt water on facilities/installations is not included. Figures at the corporate level from 2011 are verified by external auditors.

Environmental posters

Environmental overviews from our major activities in Norway, Denmark, Canada and Brazil.

CANADIAN OIL SANDS

ENERGY

diesel (gross)	28.6 GWh
electricity (gross)	146 GWh
fuel gas (gross)	1,330 GWh
flare gas (gross)	1.03 GWh

RAW MATERIALS

produced gas	11.0 mill. m³
diluent	275 mill. m³
natural gas (pipeline)	121 mill. m³
diesel	2,800 m³

WATER CONSUMPTION

Fresh water	529,000 m³

PRODUCTS

bitumen	586,000 m³

EMISSIONS TO AIR

CO_2	334,000 tonnes
NO_x	243 tonnes
CH_4 (Methane)	14.1 tonnes
SO_x	45.0 tonnes
nmVOC	42.3 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water environment	0 m³

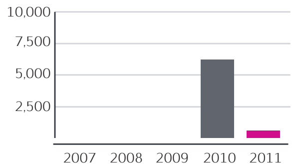
SPILLS

Oil spills	23.8 m³
Other spills	3.91 m³

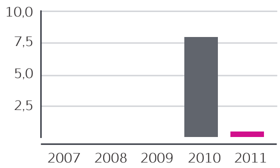
WASTE

Non-hazardous waste for deposition	14,200 tonnes
Non-hazardous waste for recovery	16.5 tonnes
Non-hazardous waste recovery rate	0.12 %
Hazardous waste for deposition	128 tonnes
Hazardous waste for recovery	6.28 tonnes
Hazardous waste recovery rate	4.66 %

CO_2
kg emissions per Scm product 1)



NO_x
kg emissions per Scm product 1)



1) 2010 was the start-up year with high energy consumption and low production.

PEREGRINO

ENERGY

Flare	119 GWh
Diesel	784 GWh
Fuel Gas	126 GWh

RAW MATERIALS

Oil	1,520,000 m³
Gas	18,400,000 m³
Produced Water	21,300 m³

UTILITIES

Chemicals process/prodn	563 tonnes
Drilling/well	58,700 tonnes

WATER CONSUMPTION

Fresh water	26.9 m³

CHEMICALS

Chemicals process/prodn	94.0 tonnes
Drilling/well	44,000 tonnes

PRODUCTS

Oil	1,520,000 m³

EMISSIONS TO AIR

CO_2	269,000 tonnes
NO_x	412 tonnes
CH_4 (Methane)	33.9 tonnes
SO_x	2,010 tonnes
nmVOC	94.0 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water environment

Produced water	519 kg
Drainage water	1.23 tonnes

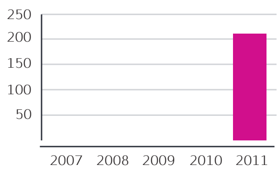
SPILLS

Oil spills	0.11 m³
Other spills	0.81 m³

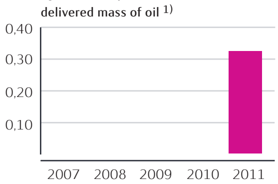
WASTE

Non-hazardous waste for deposition	170 tonnes
Non-hazardous waste for recovery	202 tonnes
Non-hazardous waste recovery rate	54 %
Hazardous waste for deposition	64.6 tonnes
Hazardous waste for recovery	209 tonnes
Hazardous waste recovery rate	76 %

CO_2
kg emissions per tonne delivered mass of oil 1)



NO_x
kg emissions per tonne delivered mass of oil 1)



1) The production started on April 8th 2011. However, emissions numbers are included since the commissioning period (January-March).

NORWEGIAN CONTINENTAL SHELF [1]

ENERGY

Diesel	2,400 GWh
Electricity	399 GWh
Fuel gas	30,800 GWh
Flare gas	3,400 GWh

RAW MATERIALS [2]

Oil/condensate	74.6 mill Scm
Gas [3]	103 bn Scm
Produced water	116 mill Scm

UTILITIES

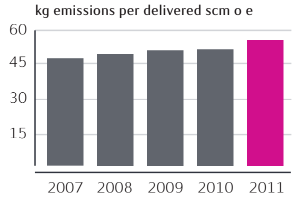
Chemicals process/prodn	59,300 tonnes
Chemicals drilling/well	180,000 tonnes

WATER CONSUMPTION

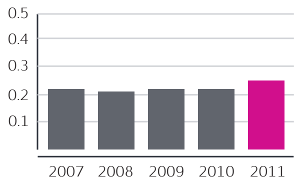
Fresh water	269,000 m³

(1) Including British part of Statfjord
(2) Includes third party processing of production on Sigyn and Skime
(3) Including fuel gas, flare gas and injected gas amongst other to pressure support
(4) Includes diffuse emissions, flaring and energy production
(5) Includes oil from produced water, drain water, ballast water and jetting
(6) Includes 75 501 tonnes water and green chemicals/substances
(7) Includes waste from onshore bases

CO_2
kg emissions per delivered scm o e



NO_x
kg emissions per delivered scm o e



PRODUCTS

Oil/condensate	74.6 mill Scm
Gas for sale	71.5 bn Scm

EMISSIONS TO AIR

CO_2	8.04 mill.tonnes
NO_x	36,000 tonnes
CH_4 (Methane) [4]	17,600 tonnes
SO_x	547 tonnes
nmVOC [4]	22,900 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water [5]	1,150 tonnes
Produced water	97.8 mill.m³
Chemicals in process/production [6]	30,400 tonnes
Chemicals in drilling/well [6]	55,000 tonnes

SPILLS

Oil spills	8.60 m³
Other spills	105 m³
Unintentional emissions of HC gas	5,820 kg

WASTE [7]

Non-hazardous waste for deposition	525 tonnes
Non-hazardous waste for recovery	15,300 tonnes
Non-hazardous waste recovery rate	97.0 %
Hazardous waste for deposition	188,000 tonnes
Hazardous waste for recovery	23,600 tonnes
Hazardous waste recovery rate	11.0 %

OTHER

Produced water injected in the ground	21.9 mill.m³

SNØHVIT LNG INSTALLATION

ENERGY

Electricy	105 GWh
Flare gas	1,020 GWh
Fuel gas	3,260 GWh
Diesel	1.00 GWh

RAW MATERIALS

Gas Snøhvit	5,180 mill. m³
Condensate Snøhvit	0.70 mill. m³

UTILITIES

Amine	64.2 m³
Caustics	246 m³
Monoethylene glycol	850 m³
Hydraulic fluids [2]	48.1 m³
Other Chemicals	41.4 m³

WATER CONSUMPTION

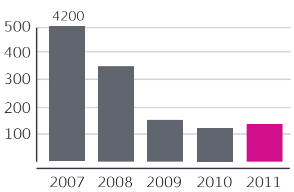
Fresh water	165,000 m³

(1) For BTEX and metals - reported half the detection limit because the HFLNG is unable to detect these substances

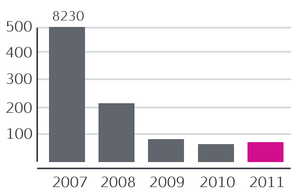
(2) Utilities include hydraulic fluids used in Hammerfest LNG Offshore/subsea part System 18

(3) Production on Melkøya started august 2007. During the startup phase we experienced high emissions levels linked primarily to flaring. The graphs reflect that the Hammerfest LNG is now in an operational phase, where the emissions per delivered volume have decreased significantly and generally come from regular operations. This is perhaps most obvious in that the emissions from turbines have increased, while the emissions from flare are reduced.

CO_2
kg emissions per delivered scm o.e. [3]



NO_x
g emissions per delivered scm o.e [3]



PRODUCTS

LNG	3,150,000 tonnes
LPG	210,000 tonnes
Condensat	520,000 tonnes

EMISSIONS TO AIR

CO_2	964,000 tonnes
NO_x	506 tonnes
CH_4 (Methane)	3,070 tonnes
SO_2	4.43 tonnes
nmVOC	1,210 tonnes
H_2S	5.93 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water environment	24.1 kg
Amine	220 kg
Ammonium	178 kg
Phenol	12.6 kg
TOC	755 kg
BTEX [1]	55.2 kg
Heavy Metals (Hg, Cr, Ni) [1]	0.99 kg
Drain water	84,100 m³

SPILLS

Oil spills	0.08 m³
Other spills	0 m³
Unintentional emissions of HC gas	810 kg

WASTE

Non-hazardous waste for deposition	180 tonnes
Non-hazardous waste for recovery	961 tonnes
Non-hazardous waste recovery rate	84.2 %
Hazardous waste for deposition	881 tonnes
Hazardous waste for recovery	259 tonnes
Hazardous waste recovery rate	22.7 %

TJELDBERGODDEN

ENERGY

Diesel	1.30 GWh
Electricity	251 GWh
Fuel gas	1,600 GWh
Flare gas	115 GWh

RAW MATERIALS

Rich gas	497,000 tonnes

UTILITIES

Caustics	281 tonnes
Acids	69 tonnes
Other chemicals	27 tonnes

WATER CONSUMPTION

Fresh water	516,000 m³

PRODUCTS

Methanol	864,000 tonnes
Oxygen	15,600 tonnes
Nitrogen	37,800 tonnes
Argon	15,400 tonnes
LNG	9,220 tonnes

EMISSIONS TO AIR

CO_2	332,000 tonnes
NO_x	196 tonnes
CH_4 (Methane)	636 tonnes
SO_x	0.86 tonnes
nmVOC	130 tonnes
Unintentional emissions of HC gas	27 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water	0 tonnes
Cooling water	198 mill.m³
Total organic carbon (TOC)	3.12 tonnes
Suspended matter	0.79 tonnes
Total-N	2.50 tonnes

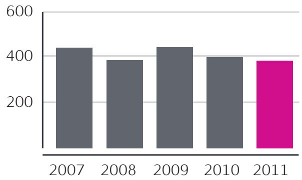
SPILLS

Oil spills	0 tonnes
Other spills	0 tonnes

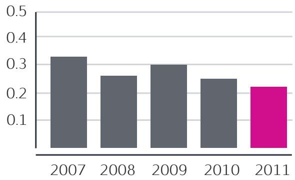
WASTE

Non-hazardous waste for deposition	22 tonnes
Non-hazardous waste for recovery	153 tonnes
Non-hazardous waste recovery rate	87.3 %
Hazardous waste for deposition	247 tonnes
Hazardous waste for recovery	28 tonnes
Hazardous waste recovery rate	10.2 %

CO_2
kg emissions per tonne product
(methanol+LNG)



NO_x
kg emissions per tonne product
(methanol+LNG)



MONGSTAD

ENERGY

Electricity consumption	1,370 GWh
Fuel gas and steam	9,040 GWh
Flare gas	277 GWh

RAW MATERIALS

Crude oil	8,800,000 tonnes
Other process raw materials[(1)]	3,350,000 tonnes
Blending components	217,000 tonnes

UTILITIES

Acids	1,120 tonnes
Caustics	3,070 tonnes
Additives	1,910 tonnes
Process chemicals	6,020 tonnes

WATER CONSUMPTION

Fresh water	4,330,000 m³

[(1)] Other process raw materials includes fuel gas from Troll gas and Refinery gas at the Combined Heat and Power plant.
[(2)] All spills are net values.
[(3)] All spills are net values.

PRODUCTS

Gasoline	3,430,000 tonnes
Gas oil	4,370,000 tonnes
Jet fuel	781,000 tonnes
Petcoke	196,000 tonnes
LPG	1,120,000 tonnes
Naphtha	1,410,000 tonnes
Suphur	14,800 tonnes
Heavy fuel (prod)	46,700 tonnes

EMISSIONS TO AIR

CO_2	2,120,000 tonnes
NO_x	1,240 tonnes
CH_4 (Methane)	6,780 tonnes
SO_x	310 tonnes
nmVOC	7,080 tonnes

DISCHARGES TO WATER

Oil in oily water	4.41 tonnes
Phenol	1.19 tonnes
Total Nitrogen	40.0 tonnes
Total organic carbon (TOC)	142 tonnes
Suspended Solids (SS)	86.5 tonnes

SPILLS

Oil spills [(2)]	0.48 m³
Other spills [(3)]	0.05 m³

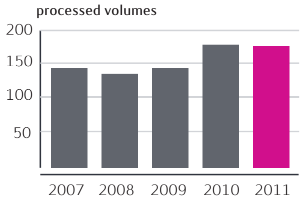
WASTE

Non-hazardous waste for deposition	622 tonnes
Non-hazardous waste for recovery	4,000 tonnes
Non-hazardous waste recovery rate	86.5 %
Hazardous waste for deposition	368 tonnes
Hazardous waste for recovery	5,000 tonnes
Hazardous waste recovery rate	93.2 %

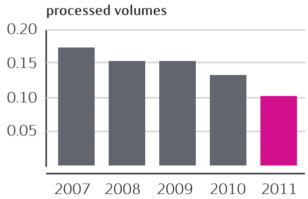
ENERGY

Electricity produced	984 GWh

CO_2
kg emissions per tonne
processed volumes



NO_x
kg emissions per tonne
processed volumes



STURE PROCESSING PLANT

ENERGY

Electricity	147 GWh
Flare gas	1.00 GWh
Fuel gas	336 GWh
Diesel	0.28 GWh

RAW MATERIALS

Crude oil	18.2 mill. scm

UTILITIES

Hydrochloric acid	7.08 tonnes
Sodium hydroxide	98.0 tonnes
Methanol	316 m³

WATER CONSUMPTION

Fresh water	614,000 m³

PRODUCTS

LPG	827,000 scm
Naphtha	498,000 scm
Crude oil export	16.7 mill. scm

EMISSIONS TO AIR

CO_2	76,500 tonnes
NO_x	33.8 tonnes
CH_4 (Methane)	272 tonnes
nmVOC	3,140 tonnes

DISCHARGES TO WATER

Treated water and open drain water	293,000 m³
TOC	47.1 tonnes
Hydrocarbons	1.08 tonnes

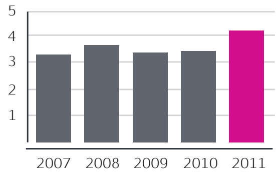
SPILLS

Oil spills	0.00 m³
Other spills	0.10 m³

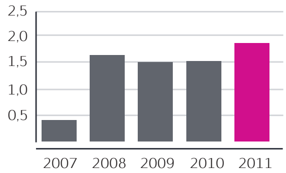
WASTE

Non-hazardous waste for deposition	41.1 tonnes
Non-hazardous waste for recovery	215 tonnes
Non-hazardous waste recovery rate	83.9 %
Hazardous waste for deposition	0.00 tonnes
Hazardous waste for recovery	171 tonnes
Hazardous waste recovery rate	100 %

CO_2
kg emissions per scm o.e. processed volumes



NO_x
g emissions per scm o.e. processed volumes



KALUNDBORG

ENERGY

Electricity [1]	178 GWh
Steam	131 GWh
Fuelgas, LPG and oil	2,230 GWh
Flare gas	69.5 GWh

RAW MATERIALS

Crude oil	4,060,000 tonnes
Other proces raw material	6,500 tonnes
Blending components	272,000 tonnes

UTILITIES

Acids	634 tonnes
Caustics	1,200 tonnes
Additives	940 tonnes
Process chemicals	1,490 tonnes
Ammonia (liquid)	2,560 tonnes

WATER CONSUMPTION

Fresh water	1,350,000 m³

[1] Imported energy (electricity and steam) are netto energy

PRODUCTS

Naphtha	61,000 tonnes
Petrol	1,340,000 tonnes
Jet fuel	39,000 tonnes
LPG (butan, propan)	60,100 tonnes
Gas oil	1,680,000 tonnes
Fuel oil	271,000 tonnes
ATS (fertiliser)	6,400 tonnes
Fuel	703,000 tonnes

EMISSIONS TO AIR

CO_2	475,000 tonnes
NO_x	516 tonnes
CH_4 (Methane)	2,090 tonnes
SO_2	358 tonnes
nmVOC	4,790 tonnes

DISCHARGES TO WATER

Regular discharges of oil to water environment	1,560 kg
Phenol	6.63 kg
Nitrogen	7,840 kg
Suspended matter	6,570 kg

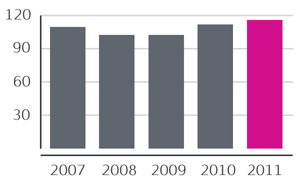
SPILLS

Oil spills	0.50 m³
Other spills	0.51 m³

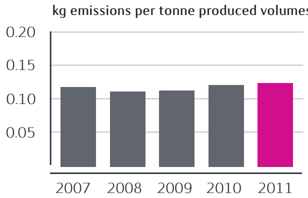
WASTE

Non-hazardous waste for deposition	75.0 tonnes
Non-hazardous waste for recovery	2,470 tonnes
Non-hazardous waste recovery rate	97.1 %
Hazardous waste for deposition	3.00 tonnes
Hazardous waste for recovery	4,780 tonnes
Hazardous waste recovery rate	99.9 %

CO_2
kg emissions per tonne produced volumes



NO_x
kg emissions per tonne produced volumes



KOLLSNES PROCESSING PLANT

ENERGY	
Electricity	1510 GWh
Flare gas	132 GWh
Fuel gas	195 GWh
Diesel	0.67 GWh

RAW MATERIALS	
Rich gas from Troll A	20.0 bn. scm
Rich gas from Troll B	1.71 bn. scm
Rich gas from Troll C	3.14 bn. scm
Rich gas from Kvitebjørn	6.72 bn. scm
Rich gas from Visund	0.57 bn. scm

UTILITIES	
Monoethyleneglycol (MEG)	468 m³
Caustic	81 m³
Acid	63 m³
Other Chemicals	125 m³

WATER CONSUMPTION	
Fresh water	57,200 m³

PRODUCTS	
Gas	32.4 bn. scm
NGL/Condensate	1.86 mill. scm

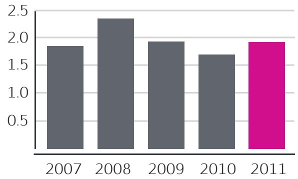
EMISSIONS TO AIR	
CO_2	66,400 tonnes
NO_x	35.7 tonnes
CH_4 (Methane)	1280 tonnes
SO_x	0.21 tonnes
nmVOC	608 tonnes

DISCHARGES TO WATER	
Treated water and open drain water	149,000 m³
Regular discharges of oil	0.02 tonnes
Regular discharges of TOC	2.20 tonnes
Regular discharges of ammonium	0.02 tonnes
Regular discharges of phenol	0.01 tonnes
Regular discharges of methanol	0.11 tonnes
Regular discharges of MEG	1.60 tonnes

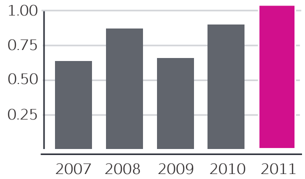
SPILLS	
Oil spills	0.09 m³
Other spills	0.20 m³

WASTE	
Non-hazardous waste for deposition	36.6 tonnes
Non-hazardous waste for recovery	905 tonnes
Non-hazardous waste recovery rate	96.1 %
Hazardous waste for deposition	241 tonnes
Hazardous waste for recovery	1240 tonnes
Hazardous waste recovery rate	83.7 %

CO_2
kg emissions per delivered scm o e



NOx
g emissions per delivered scm o e



KÅRSTØ GAS PROCESSING PLANT

ENERGY	
Flare gas	149 GWh

RAW MATERIALS	
Rich gas	21.1 mill. tonnes
Condensate	2.67 mill. tonnes

UTILITIES	
Hydrochloric acid	475 tonnes
Sodium hydroxide	186 tonnes
Ammonia	15.1 tonnes
Methanol	9.2 tonnes
Other chemicals	6.1 tonnes

WATER CONSUMPTION	
Fresh water	0.90 mill m³

PRODUCTS	
Lean gas	17.7 mill tonnes
Propane	2.34 mill tonnes
I-butane	0.50 mill tonnes
N-butane	0.95 mill tonnes
Naphtha	0.64 mill tonnes
Condensate	1.50 mill tonnes
Ethane	0.86 mill tonnes
Electricity sold	0 GWh

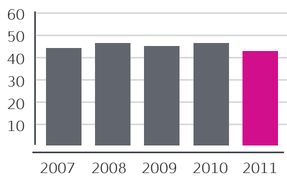
EMISSIONS TO AIR	
CO_2	1,020,000 tonnes
NO_x	601 tonnes
CH_4 (Methane)	1,260 tonnes
SO_x	6.4 tonnes
nmVOC	1,500 tonnes
Unintentional HC-gas emissions	0 tonnes

DISCHARGES TO WATER	
Cooling water	387 mill m³
Treated water	0.8 mill m³
Oil in oily water	496 kg
Total organic carbon (TOC)	5.7 tonnes

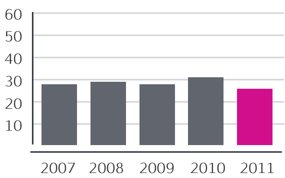
SPILLS	
Oil spills	0 m³
Other spills	0 m³

WASTE	
Non-hazardous waste for deposition	123 tonnes
Non-hazardous waste for recovery	1,950 tonnes
Non-hazardous waste recovery rate	94 %
Hazardous waste for deposition	41 tonnes
Hazardous waste for recovery	1,930 tonnes
Hazardous waste recovery rate	98 %

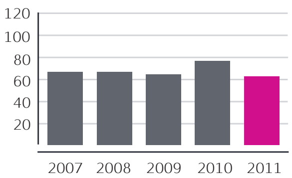
CO_2
kg emissions per tonne product



NO_x
g emissions per tonne product



nmVOC
g emissions per tonne product



Recommendation of the corporate assembly

Resolution:
At its meeting of 22 March 2012 the corporate assembly discussed the 2011 annual accounts of Statoil ASA and the Statoil group, and the board of directors' proposal for the allocation of net income.

The corporate assembly recommends that the annual accounts and the allocation of net income proposed by the board of directors are approved.

Oslo, 22 March 2012

Olaug Svarva
Chair of the corporate assembly

Corporate assembly
Olaug Svarva, Idar Kreutzer, Karin Aslaksen, Greger Mannsverk, Steinar Olsen, Ingvald Strømmen, Rune Bjerke, Tore Ulstein, Live Haukvik Aker, Tor Oscar Bolstad, Barbro Hætta-Jacobsen, Siri Kalvig, Oddbjørn Viken, Eldfrid Irene Hognestad, Stig Lægreid, Per Martin Labråthen, Anne K. S. Horneland, Jan-Eirik Feste, Per Helge Ødegård, Brit Gunn Ersland and Frode Solberg.

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