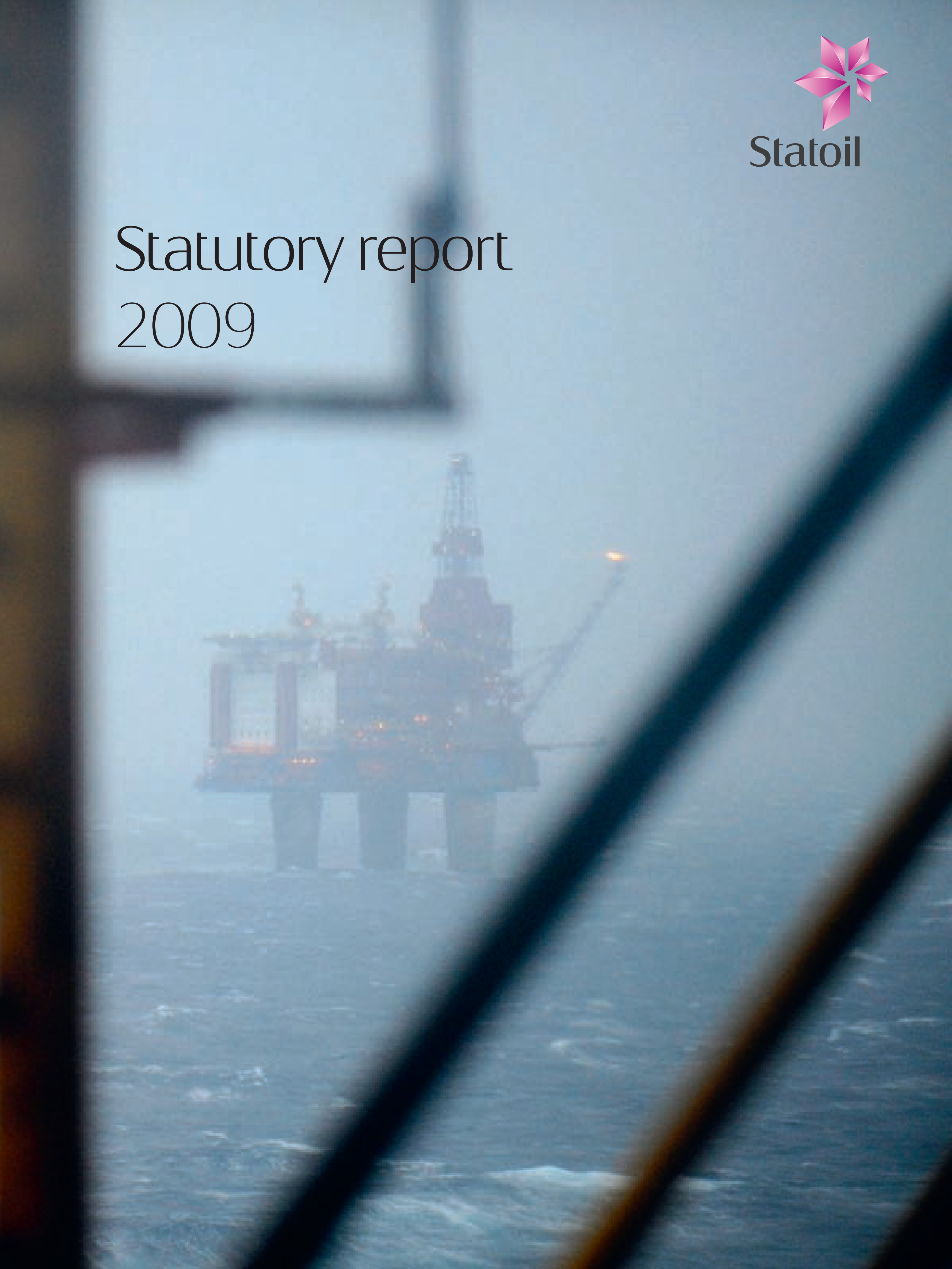
Statoil

Statutory report 2009



Statutory report 2009

Board of directors report

Statoil delivered a strong operational performance in 2009. The company has a solid financial position and is well placed to continue to deliver long term growth and shareholder value.

The company increased its equity production in 2009 by 2% to 1.962 mboe per day. Statoil also delivered a successful exploration programme, while maintaining a strict cost control and capital discipline. However, net operating income was down by 39%, mainly because of lower prices for both oil and gas. Net operating income amounted to NOK 121.6 billion.

Around 80% of the synergies from the merger in 2007 have been achieved. Additional cost savings have been implemented during 2009.

The company has had a strong cash flow through times of financial turmoil and has maintained its sound financial position. Statoil is thus positioned to deliver according to its stated production guidance for 2012, despite the current weakness in the gas markets. The group has a strong resource potential and a high quality project portfolio to underpin profitable growth also beyond 2012.

The Statoil share

The board of directors proposes a dividend of NOK 6.00 per share for 2009 making a total of NOK 19.1 billion.

The board of directors has decided to make adjustments to the dividend policy in order to establish a more predictable dividend level going forward. The new policy does not imply any change in the long-term dividend level, including potential share buy-backs, compared to the previous policy. The ambition is to grow the annual cash dividend, measured in NOK per share, in line with long-term underlying earnings. When proposing the annual dividend level, the board of directors will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility.

In 2008, ordinary dividend was NOK 4.40 per share, as well as NOK 2.85 per share in special dividend for a total of NOK 7.25 per share and an aggregate total of NOK 23.1 billion.

The Statoil share price development reflected the growing economic optimism as the share price is showing an upward trend during 2009, starting out 2 January 2009 at NOK 118.40, ending up at NOK 144.80 at the end of 2009.

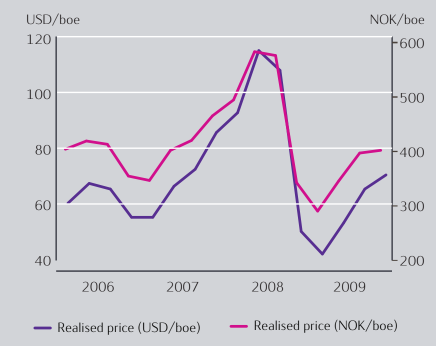
Group profit and loss analysis

Net operating income was NOK 121.6 billion in 2009, compared to NOK 198.8 billion in 2008.The decrease was primarily attributable to lower prices of liquids and gas, and increased depreciation, amortisation and impairment losses, partly offset by income from higher volumes sold.

Consolidated statement of income (in NOK billion)	For the year ended 31 December 2009	2008	Change
Revenues and other income			
Revenues	462.3	652.0	(29%)
Net income from associated companies	1.8	1.3	39%
Other income	1.4	2.8	(51%)
Total revenues and other income	465.4	656.0	(29%)
Operating expenses			
Purchase, net of inventory variation	205.9	329.2	(37%)
Operating expenses	56.9	59.3	(4%)
Selling, general and administrative expenses	10.3	11.0	(6%)
Depreciation, amortisation and net impairment losses	54.1	43.0	26%
Exploration expenses	16.7	14.7	14%
Total operating expenses	343.8	457.2	(25%)
Net operating income	121.6	198.8	(39%)
Net financial items	(6.7)	(18.4)	(64%)
Income tax	(97.2)	(137.2)	(29%)
Net income	17.7	43.3	(59%)
Earnings per share for income attributable to equity holders of company basic and diluted	5.7	13.6	(58%)

Revenues and other income was NOK 465.4 billion in 2009, compared to NOK 656.0 billion in 2008. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products. 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.

Group realised oil prices



The NOK 190.6 billion decrease in revenues from 2008 to 2009 was mainly attributable to lower prices of both liquids and gas. Realised prices of liquids measured in NOK decreased by 29% from 2008 to 2009, contributing NOK 56.5 billion to the reduction in revenues. Gas prices were down 21% in 2009 compared to last year, and contributed NOK 25.0 billion to the reduction in revenues. The reduction in revenues was partly compensated by the 4% increase in liftings of both liquids and gas, with a total off-setting effect of NOK 15.2 billion. The decrease in revenues related to volumes purchased from The Norwegian state contributed NOK 124.3 billion.

Total liquids liftings amounted to 1.045 mmboe per day in 2009, an increase of 3% compared to last year.

Total liftings of gas increased by 6% from 696 mboe per day in 2008 to 740 mboe per day in 2009.

Net income from associated companies was NOK 1.8 billion in 2009 compared to NOK 1.3 billion in 2008.

Other income was NOK 1.4 billion in 2009, compared with NOK 2.8 billion in 2008. The income in 2009 was mainly related to income from insurance proceeds regarding business interruptions. The income in 2008 was mainly related to gain from sale of assets.

Purchase, net of inventory variation amounted to NOK 205.9 billion in 2009, compared to NOK 329.2 billion in 2008. The 37% decrease from 2008 to 2009 mainly stem from lower prices of liquids measured in NOK.

Operating expenses include field production and transport systems costs related to the company's share of oil and natural gas production. Operating expenses were NOK 56.9 billion in 2009, which is a reduction of 4% since 2008. The reduction was mainly attributable to reduced transportation costs and the reversal of provisions related to a take-or-pay contract in previous periods.

Total liquids and gas entitlement production increased from 1.751 mmboe per day in 2008 to 1.806 mmboe per day in 2009. Equity production of oil and gas increased from 1.925 mmboe per day in 2008 to 1.962 mmboe per day in 2009.

The production cost per boe based on equity volumes for the two periods was NOK 35.3 and NOK 34.6, respectively. Adjusted for restructuring costs and other costs arising from the merger recorded in the fourth quarter of 2007 and gas injection costs, the production cost per boe for the 12 months ending 31 December 2009 and 2008, was NOK 35.3 and NOK 33.3, respectively.

Selling, general and administrative expenses amounted to NOK 10.3 billion in 2009, compared to NOK 11.0 billion in 2008. The improvement is mainly due to cost savings.

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 write-downs of impaired long-lived assets and reversals of impairments. These expenses amounted to NOK 54.1 billion in 2009, compared to NOK 43.0 billion in 2008. The 26% increase in depreciation, amortisation and impairment expenses was mainly due to increased production and impairment charges net of reversals of NOK 7.1 billion, mostly related to assets in the Gulf of Mexico and refinery assets in Norway and Denmark.

Exploration expenditures are capitalised to the extent that exploration efforts are considered successful, or pending such assessment. Otherwise, such expenditures are expensed. The exploration expense consists of the expensed portion of our exploration expenditure in 2009 and write-offs of exploration expenditure capitalised in previous years. In 2009, the exploration expenses were NOK 16.7 billion, up 14% from 2008. The increase was mainly due to a higher number of wells drilled and a higher portion of exploration expenditure capitalised in previous years being impaired.

	For the year ended 31 December		
Exploration (in NOK billion)	2009	2008	change
Exploration expenditure (total activity level)	**16.9**	17.8	(5%)
Expensed, previously capitalised exploration expenditure	**7.0**	3.7	89%
Capitalised share of current periods exploration activity	**(7.2)**	(6.8)	6%
Exploration expense	**16.7**	14.7	14%

In 2009, a total of 68 **exploration and appraisal wells** and two exploration extension wells were completed, 41 on the NCS and 29 internationally. Thirty-eight exploration and appraisal wells and two exploration extension wells have been declared as discoveries. In 2008, a total of 79 exploration and appraisal wells and nine exploration extension wells were completed, 48 on the NCS and 40 internationally. Thirty-five exploration and appraisal wells and six exploration extension wells were declared as discoveries.

Net operating income was NOK 121.6 billion in 2009, compared to NOK 198.8 billion in 2008. The decrease was primarily attributable to lower prices of liquids and gas, and increased depreciation, amortisation and impairment losses, partly offset by income from higher volumes sold.

In 2009, net operating income was affected by the following items: impairment losses net of reversals (NOK 12.2 billion) and underlift (NOK 1.2 billion) negatively affected net operating income, while higher fair value of derivatives (NOK 2.2 billion), higher values of products in operational storage (NOK 2.1 billion), other accruals (NOK 1.3 billion), gain on sale of assets (NOK 0.5 billion) and reversals of restructuring costs (NOK 0.3 billion) all positively affected net operating income in 2009.

In 2008, net operating income was affected by the following items: impairment charges net of reversals (NOK 4.8 billion), lower values of products in operational storage (NOK 2.8 billion), underlift (NOK 2.4 billion) and other accruals (NOK 2.3 billion) all affected net operating income in 2008 negatively, while increased fair value of derivatives (NOK 1.8 billion), gains on derivatives to hedge the value of inventories (NOK 0.8 billion), gains on sales of assets (NOK 1.4 billion) and reversal of restructuring cost accrual (NOK 1.6 billion) positively affected net operating income in 2008.

Net financial items amounted to a loss of 6.7 billion in 2009, compared to a loss of NOK 18.4 billion in 2008. The NOK 11.7 billion positive change was mostly attributable to NOK 2.0 billion net currency gains caused by a 17% weakening of US dollar versus the NOK for the year ended 31 December 2009, compared to NOK 32.6 billion in net currency losses caused by a 29% strengthening of the US dollar versus the NOK for the year ended 31 December 2008.

Income taxes were NOK 97.2 billion in 2009, equivalent to a tax rate of 84.6%, compared to NOK 137.2 billion in 2008, equivalent to a tax rate of 76.0%. The increase in the tax rate from 2008 to 2009 was mainly due to significant taxable exchange gains, which do not have an impact on the statement of income for companies in the group whose functional currency is USD. In 2009 the taxable income related to these exchange gains is estimated to be NOK 25.0 billion higher than income before tax, which increases the tax rate. In addition, the tax rate was increased by relatively higher income from the NCS with higher than average tax rates, and impairment losses with lower than average tax rates.

In 2009, the **non-controlling interest** (minority interest) in net profit was negative NOK 0.6 billion, compared to NOK 0.005 billion in 2008. The non-controlling interest is primarily related to the Mongstad refinery.

Net income was NOK 17.7 billion in 2009, compared to NOK 43.3 billion in 2008. The 59% decrease from 2008 to 2009 is mainly due to reduced operating income caused by lower revenues from liquids and gas sales and a higher effective tax rate, only partly offset by reduced loss on net financial items.

Considering the proposed dividend for 2009, the remaining net income in the parent company will be allocated to reserve for valuation variances and retained earnings with NOK 14.9 billion and NOK (5.1) billion, respectively. The company's distributable equity after allocations amounts to NOK 98.1 billion.

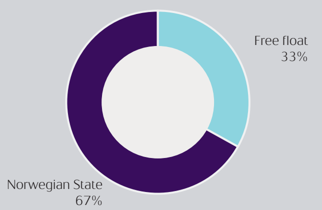
In accordance with Section 3-3 of the Norwegian Accounting Act, the board of directors confirms that the financial statements have been prepared on the basis of the **going concern** assumption.

Our business

Statoil is an integrated energy company based in Norway. The company is present in 40 other countries worldwide. We are the leading operator on the NCS and are also experiencing strong growth in our international production.

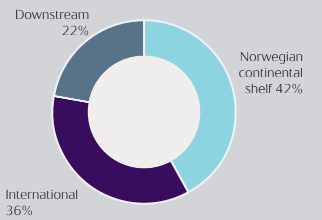
Statoil ASA is a public limited company organised under the laws of Norway. The largest offices are in Stavanger, Bergen and Oslo, and the group had approximately 29,000 employees as of 31 December 2009.

Ownership structure *

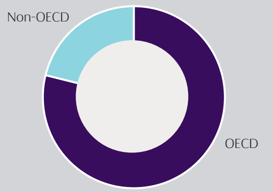


*As per 31 December 2009

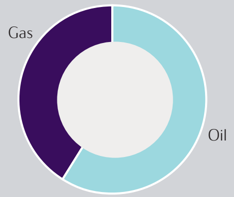
Fixed assets



Upstream assets



Oil and gas*



*Entitlement production

The combined exploration and production business had an average equity liquids and natural gas production of 1,962 mmboe per day, and as of 31 December 2009, Statoil had proved reserves of 2,174 mmbbl of oil and 514 bcm of natural gas, corresponding to aggregate proved reserves of 5,408 mmboe.

Statoil ranks among the world's largest net sellers of crude oil and condensate and is the second largest supplier of natural gas to the European market. We have also substantial processing and refining activities and have approximately 2000 service stations in Scandinavia, Poland, the Baltic States and Russia.

Statoil is contributing to developing new energy resources, and have ongoing activities in the fields of wind power and marine biofuels. The company is at the forefront in implementing technologies for carbon capture and storage (CCS).

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

Statoil business areas are presented below:

Exploration & Production Norway is responsible for Statoil's exploration, field development and production operations on the Norwegian Continental Shelf (NCS). Total production amounted to 1.45 mmboe per day in 2009, representing 74% of Statoil's equity production.The business area had approximately 8,000 employees as of 31 December 2009.

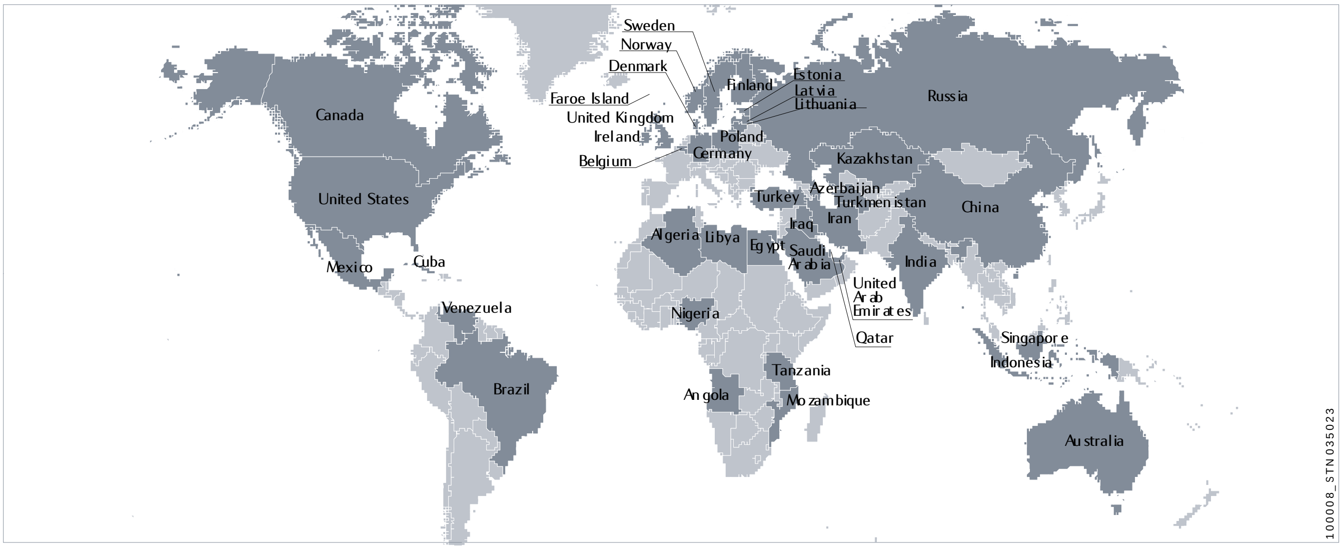
International Exploration & Production is responsible for exploration, development and production of oil and gas outside the NCS. Total production amounted to 512 mboe per day in 2009, representing 26% of Statoil's equity production. The business area had approximately 1,700 employees as of 31 December 2009.

Natural Gas is responsible for Statoil's transportation, processing and marketing of pipelined gas and LNG worldwide, including the development of additional processing, transportation and storage capacity. The business area had approximately 1,300 employees as of 31 December 2009.

Manufacturing & Marketing is responsible for the processing and sale of our production of crude oil and natural gas liquids (NGL), and the sale of refined products. The business area also markets and sells the Norwegian State's volumes of crude and NGL. The business area had approximately 11,300 employees as of 31 December 2009.

Technology & New Energy is responsible for the development of technology and renewable energy. The business area had approximately 2,800 employees as of 31 December 2009.

Projects is responsible for planning and executing all development and modification projects exceeding NOK 50 million. The business area had approximately 1,100 employees as of 31 December 2009.



Cash flows

Cash flows from underlying operations, less tax payments, contributed NOK 81.5 billion. Cash flows used in investing activities amounted to NOK 75.4 billion.

Cash flows from operating activities

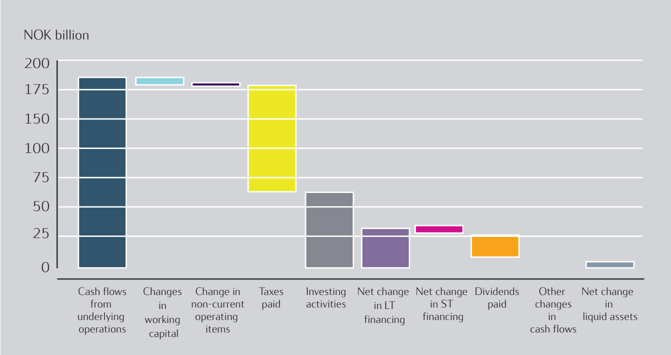
Statoil's primary source of cash flow consists of funds generated from operations. Cash flow provided by operating activities was NOK 73.0 billion in 2009, compared to NOK 102.5 billion in 2008. Adjusting for changes in cash flows due to changes in working capital and other non-current items related to operating activities, cash flows from underlying operations less tax payments contributed NOK 81.5 billion.

The NOK 29.5 billion decrease in cash flows from operating activities was primarily due to a NOK 57.9 billion decrease in cash flows from underlying operations, an increase in cash flows used due to changes in working capital of NOK 7.0 billion and a decrease in cash flows from non-current items related to operating activities of NOK 3.7 billion. These effects were partly offset by a decrease in taxes paid of NOK 39.1 billion.

Cash flows used in investing activities

Cash flows used in investing activities amounted to NOK 75.4 billion in 2009, a NOK 10.5 billion decrease from 2008. The decrease stems mostly from acquisitions paid for in 2008, partly offset by NOK 3.9 billion less in proceeds from sales.

Sources and use of cash flows in 2009



Cash flows used in financing activities

Net cash flows provided by financing activities for 2009 amounted to NOK 11.3 billion, compared to cash flow used in financing activities of NOK 17.0 billion for 2008. The NOK 28.3 billion change was mainly related to NOK 41.7 billion in net changes in long-term borrowing and NOK 4.0 billion in less dividend paid in 2009, partly offset by repayment of short-term borrowings by NOK 7.1 billion in 2009, compared with an increase in short-term borrowings by NOK 10.5 billion in 2008.

Liquidity and capital resources

Statoil has maintained a strong financial position through times of financial turmoil with a net debt ratio of 27% at year end 2009.

Liquidity

Our annual cash flow from operations is highly dependent on oil and gas prices and our levels of production. It is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside our control, will cause fluctuations in our cash flows. We will use available liquidity to finance Norwegian petroleum tax payments, any dividend payment and investments.

As of 31 December 2009, we had liquid assets of NOK 31.7 billion, including NOK 24.7 billion in cash and cash equivalents and NOK 7.0 billion of current financial investments. Compared to year end 2008, current financial investments decreased by NOK 2.7 billion during 2009, and cash and cash equivalents increased by NOK 6.1 billion. The increase of liquid assets during 2009 was mainly due to new long term debt. As of 31 December 2009, the group also had USD 2.0 billion available in a committed revolving credit facility from international banks, including a USD 500 million swing-line facility. The facility is available for drawdowns until December 2011.

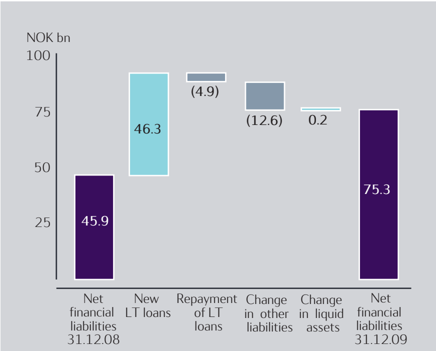
Statoil's general policy is to maintain a liquidity reserve in the form of cash and cash equivalents in its balance sheet, and committed, unused credit facilities and credit lines in order to ensure that it has sufficient financial resources to meet its short-term requirements. Long-term funding is raised when the group identifies a need for such financing based on its business activities and cash flows, as well as when market conditions are considered favourable.

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 different risk assessments, some of them in line with financial matrices used by S&P and Moody's, such as free cash flow from operations over net debt and net debt to capital employed.

Our long-term and short-term ratings from Moody's are Aa2 and P-1, respectively. Our long-term rating from Standard & Poor's is AA-, reflecting the majority ownership by the Norwegian state. Standard & Poor's short-term rating of Statoil is A-1+. The current rating outlook is stable from both agencies.

Statoil will in 2010 continue to secure necessary financial flexibility and, depending upon oil- and gas price development, may issue bonds if market conditions are viewed as attractive.

Net interest bearing financial liabilities



Net interest-bearing financial liabilities amounted to NOK 75.3 billion at 31 December 2009, compared to NOK 46.0 billion at 31 December 2008. The change of NOK 29.3 billion was mainly related to an increase in non-current financial liabilities of NOK 41.1 billion, decreased current financial liabilities of NOK 12.5 billion, and an increase in cash, cash equivalents and current financial investments of NOK 3.4 billion.

The net debt to capital employed ratio, defined as net interest-bearing debt in relation to capital employed, was 27.3% at 31 December 2009, compared with 17.5% at 31 December 2008. The 9.8% increase was mainly related to an increase of net financial liabilities of NOK 29.3 billion, in combination with an increase in capital employed of NOK 13.4 billion.

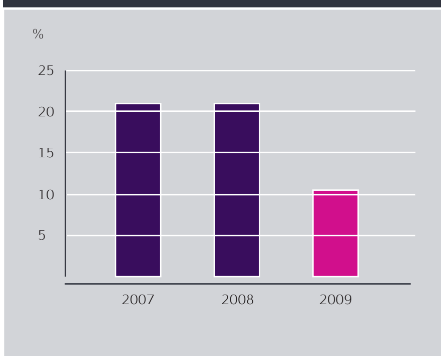
The group's borrowing needs are mainly covered through the issuing of short-term and long-term securities, including utilisation of a US Commercial Paper Programme and a Euro Medium Term Note (EMTN) Programme (the limits of the programme being USD 4 billion and USD 6 billion, respectively), and through draw-downs under committed credit facilities and credit lines. After the effect of currency swaps, 100% of our borrowings are in US dollars.

Our **financial policies** take into consideration funding sources, the maturity profile of long-term debt, interest rate risk management, currency risk and management of liquid assets. Our borrowings are denominated in various currencies and swapped into USD, since the largest proportion of our net cash flow is denominated in USD. In addition, we use interest rate derivatives, primarily consisting of interest rate swaps, to manage the interest rate risk of our long-term debt portfolio.

Return on Average Capital Employed

Statoil achieved a competitive rate of return on the capical employed in 2009.

Return on capital employed (ROACE)



We use ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. ROACE was 10.4% in 2009, compared with 21.0% in 2008. The decrease from last year was due to a 43% drop in net income adjusted for financial items after tax and a 15% increase in capital employed. ROACE is defined as a non-GAAP financial measure.

Research and Development

Statoil is a technology intensive company. Research and development is an integral part of our strategy.

In addition to technological development in field development projects, a significant part of Statoil's research is carried out at centres for research and technology development in Trondheim, Bergen, Porsgrunn in Norway and Calgary in Canada. The research and development is carried out in close co-operation with universities, research institutions, other operators and the supplier industry. Research and development expenditures were NOK 2.1 billion in 2009.

The technology strategy is driven by our key business challenges, aiming to build even stronger industry positions. Technology is a key enabler to achieving this and will make significant contributions to field development in frontier deep waters and Arctic areas, heavy oil production, subsalt exploration, and environmental and climate issues. The ambition is to achieve distinctiveness and industry leadership in selected technologies and to stay competitive in a broad range of core and emerging technologies along the energy provision value chain.

Furthermore, improved oil and gas recovery and improved drilling and well solutions are important to successfully fight declining production from mature fields. Statoil has achieved some of the petroleum industry's highest recovery factors on the NCS by combining scientific and engineering capabilities and boldly introducing new technology. We intend to further advance the most important technologies to meet our improved oil recovery ambitions.

Risks

The financial results are very dependent upon the prices of crude oil and natural gas, the USDNOK exchange rate and realised refining margins.

The financial results of operations largely depend on a number of factors, most significantly those that affect the price we receive in NOK for our sold products. Specifically, such factors include the level of crude oil and natural gas prices; trends in the exchange rate between the USD and NOK; equity production and entitlement sales volumes of liquids and natural gas; available petroleum reserves, and Statoil's, as well as its partners' expertise and co-operation in recovering oil and natural gas from those reserves; and changes in the portfolio of assets due to acquisitions and disposals.

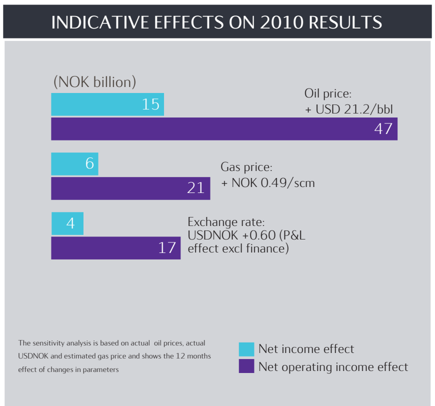
The results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which the group operates. Also possible or continued actions by members of the Organization of Petroleum Exporting Countries (Opec) that affect price levels and volumes, refining margins, increasing cost of oilfield services, supplies and equipment, increasing competition for exploration opportunities and operatorships, and deregulation of the natural gas markets 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 contract prices, Statoil's benchmark refining margins (FCC margin) and the USDNOK exchange rates for 2009, 2008 and 2007.

Yearly average	2009	2008	2007	2006
Crude oil (USD/bbl brent blend)	58.0	91.0	70.5	63.2
Natural gas (NOK per scm)(1)	1.9	2.4	1.7	1.9
FCC margins (USD/bbl)(2)	4.3	8.3	7.5	7.1
USDNOK average daily exchange rate	6.3	5.6	5.9	6.4

(1) From the Norwegian Continental Shelf.

(2) Refining margin.



The illustration shows how certain changes in the crude oil price, natural gas contract prices and the USDNOK exchange rate, if sustained for a full year, could impact the financial results in 2010.

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 the financial results would differ from those that would actually appear in our consolidated financial statements because our consolidated financial statements would also reflect the effect on depreciation, trading margins, exploration expenses, inflation, potential tax system changes and the effect of any hedging programmes in place.

Our oil and gas price hedging policy is designed to assist our long-term strategic development and our attainment of targets by protecting financial flexibility and cash inflows.

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, while our operating expenses and income taxes payable largely accrue in NOK. The group seek to manage this currency mismatch by issuing or swapping long-term debt in USD. This debt policy is an integrated part of our total risk management programme. The group also engage in foreign currency hedging 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 long-term debt portfolio. In general, an increase in the value of USD in relation to NOK can be expected to increase our reported earnings.

Group outlook

Statoil's guidance for **equity production** is between 1,925 and 1,975 mboe per day in 2010 and between 2.1 and 2.2 mmboe per day in 2012. The expected volumes are exclusive of any Opec cuts. Commercial considerations related to gas sales activities, operational regularity, the timing of new capacity coming on stream and gas off-take represent the most significant risks related to the production guidance.

Capital expenditures for 2010, excluding acquisitions and capital leases, are estimated to be around USD 13 billion.

Unit production cost for equity volumes is estimated to be NOK 35-36 per boe, which is on par with 2009.

The company will continue to mature the large portfolio of **exploration** assets and expects an exploration activity level in 2010 of around USD 2.3 billion.

We anticipate that **prices for crude oil, products and natural gas** will continue to be volatile in the short to medium term. Refining margins have been low for more than a year, and we anticipate that they will remain rather low in the short to medium term.

In the long term, we maintain our positive 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 US we believe that our position in the Marcellus shale gas acreage, in combination with Gulf of Mexico production and our LNG regasification capacity position at the Cove Point terminal in Maryland will provide a foundation for growth in our US market position in the years to come.

Statoil's income could vary significantly with changes in commodity prices, while volumes are fairly stable through the year. There is a small seasonal effect on volumes between 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 from a higher level of maintenance of offshore production facilities since generally better weather conditions allow for more maintenance work during the second and third quarter each year.

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.

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 is our first priority.

We suffered six fatal accidents in 2009. Three of our employees in Brazil were on board Air France flight 447 which disappeared over the Atlantic on 1 June. On 7 May 2009 we experienced an accident in connection with the dismantling of scaffolding on Oseberg B, when one of our contractor employees was fatally injured. On 7 September a fatal accident occurred on the LPG carrier "Lady Shana" during a port call at Petit Couronne in France, when one crew member fell from the shore gangway and into the river Seine. On 17 October a fatality occurred when one of our contractor employees was fatally injured during work at the Leismer project in Canada.

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 order to meet our goal of improving safety results in all our businesses, we hold a large number of training sessions in compliance and risk management.

Major organisational changes have been planned and implemented in a safe manner. For Statoil's North Sea operations, strong cooperation between offshore units, onshore support functions and management is essential. A new organisational model has now been implemented, and there is a particular focus on risk management in this respect. Compensatory measures are continuously implemented in order to reduce the probability of any kind of accident occuring.

Our compliance programme focuses on the integration of our values in all activities, and on compliance with internal and external requirements. Where requirements cannot be met, the risk will be identified and controlled as part of the systematic handling of non-conformities.

Statoil's safety results with respect to serious incidents have been at a stable level in recent years. The overall Serious Incident Frequency (SIF) improved from 2.2 in 2008 to 1.9 in 2009.

We strive to ensure a working environment that promotes job satisfaction and good health. 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 was 4% in 2009, and is followed closely by managers at all levels.

Statoil was fined NOK 25 million by the public prosecution authorities in Norway on 18 December 2009 in connection with an oil leakage incident that took place on 12 December 2007 on the Norwegian continental shelf.

People and the organisation

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

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 the 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.

The group has recently reviewed its global people policies to ensure consistent common standards across the group. 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 it continues 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.

By December 2009, 37% of our employees were women, and 40% of the members on the board of directors were women. Of the 84 senior vice presidents, 24% are female, and 35% of our successor pool for these roles are female. The proportion of female managers was 25%, and among managers under the age of 45 the proportion was 34%.

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. In 2009, we worked systematically on the development, deployment and succession planning of business-critical leadership positions. Of leaders promoted to the top 170 roles in 2009, 47% were female.

Salary ratio men to women

Statoil works systematically with recruitment and development programmes in order to increase the number of women in male-dominated positions and discipline areas. 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.

The Statoil group employs approximately 29,000 permanent employees in 41 countries, and more than 18,000 of them are employed in Norway, whereas approximately 11,000 were employed outside Norway. Of these, 9,400 were employed in the retail business.

Geographical Region	2009	Number of employees 2008	2007	2009	women 2008	2007
Norway	18,100	17,891	17,959	31%	30%	29%
Rest of Europe	9,593	10,475	10,151	50%	47%	46%
Africa	165	144	117	28%	32%	34%
Asia	150	169	144	55%	54%	52%
North America	584	448	315	34%	39%	33%
South America	147	102	72	48%	53%	53%
TOTAL	28,739	29,229	28,758	37%	35%	37%
Non - OECD	2,703	3,009	2,904	64%	65%	66%

Environment and climate

The group works actively to limit the negative environmental impacts related to its operations.

The group is committed through its climate policy to contribute to sustainable developments. We recognise that there is a 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, as well as the need to increase company efforts on renewables and clean technology. Statoil's environmental management system seeks to identify the most important environmental aspects of all facilities, set targets for improvement, and is an integrated part of the overall management system.

Our 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. The climate policy has been implemented in all our business planning and strategy development.

Statoil is continuously focusing on energy efficiency at our installations. Requirements for energy efficiency are incorporated in relevant governing documents.

We continuously monitor our emissions. 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 program aimed at adapting its oil spill response to arctic areas.

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

The current emissions of $CO2$ per tonne of oil and gas produced from Statoil-operated fields at the Norwegian Continental Shelf in 2009 correspond to 43% of the oil and gas industry 2009 average.The volume of accidental oil spills decreased from 342 cubic metres in 2008 to 170 cubic metres in 2009. Carbon dioxide emissions have decreased from 14.4 million tonnes in 2008, to 13.1 million tonnes in 2009. Nitrogen oxides emissions have decreased from 46.7 thousand tonnes in 2008 to 42.3 thousand tonnes in 2009. Energy consumption has decreased from 69.6 TWh in 2008 to 63.6TWh in 2009. The recovery rate for non-hazardous waste has increased from 29% in 2008 to 68.7% in 2009.

Society

Statoil has continued to strengthen compliance with its policies and standards for social responsibility, ethics and anti-corruption across its operations throughout 2009.

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 its stakeholders. This is not only an ethical imperative. 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 the group's interests and the interests of the affected societies
- ensuring transparency, anti-corruption, and respect for human rights and labour standards
- generating positive spin-offs from core activities to help meet the aspirations of the societies in which the group operates

Throughout 2009, we have continued to strengthen compliance with our policies and standards for social responsibility and ethics and anti-corruption across our operations. Stricter requirements and processes for integrity due diligence for assessing and managing risks in its business relationships have been implemented. To further comply with our Ethics Code of Conduct policy, the group rolled out an ethics training and awareness programme reaching staff from 37 countries of operation, especially targeting senior management, procurement staff and others regularly exposed to third parties.

We have commenced an extensive process for the implementation of the Voluntary Principles on Security and Human Rights (VPSHR) in priority countries. That process, which is still in progress, includes performing a human rights due diligence focusing on the company's security arrangements, addressing any identified risks and networking with international and/or local NGOs or other appropriate organisations to provide training on the VPSHR.

In 2009, the focus was 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.

The "Horton case" was finally closed by the US authorities on 19 November 2009 after Statoil had successfully fulfilled its obligations under the Settlements with the Department of Justice and the Securities and Exchange Commission (SEC) entered into in October 2006 as a result of the so-called "Horton Affair". The closing of the court case was a formal recognition that Statoil had fulfilled all the conditions of the settlements entered into with the US authorities.

We continue to promote local sourcing and we look for opportunities to support sustainable and competitive enterprises in many of our countries of operations. In 2009, we spent an estimated NOK 2.5 billion on goods and services from companies based in non-OECD countries, down from NOK 3.1 billion in the previous year. Our business also generates significant revenues for governments. In 2009, we made total payments and contributions to governments estimated at NOK 145.8 billion. Direct and indirect taxes paid in Norway amounted to NOK 102.1 billion, and direct and indirect taxes paid outside Norway totalled NOK 23.7 billion in 2009.

Statoil procurements from local suppliers in non-OECD countries was approximately NOK 2.5 billion in 2009, compared to NOK 3.1 billion in 2008. The group invested in capacity-building and skills development for its local employees and communities alike, as well as in local enterprise skills upgrading and development in Brazil, Canada and Nigeria to provide them with the right skills and expertise, standards and certifications required to compete successfully and work in the oil and gas industry.

Board developments

Jakob Stausholm is a new member of the board of Statoil ASA since July 2009, and is also member of the board's audit committee. Stausholm replaced Kurt Anker Nielsen. Einar Arne Iversen, elected by the employees, is also new member of the board of Statoil ASA since June 2009 and replaces Claus Clausen. Geir Nilsen and Ragnar Fritsvold were observers in the board up to June 2009.

The board held 11 meetings in 2009 and the meeting attendance was 94%.

The board's audit committee held six meeting in 2009 and the meeting attendance was 95%.

The compensation committee held eight meetings in 2009 and the meeting attendance was 81%.

Stavanger, 17 March 2010

THE BOARD OF DIRECTORS OF STATOIL ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

ROY FRANKLIN

ELISABETH GRIEG

EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

JAKOB STAUSHOLM

MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

Statement on compliance

Board and management confirmation

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 2009.

To the best of our knowledge, we confirm that:

- the Statoil ASA consolidated annual financial statements for 2009 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 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 uncertanties of the company and the group.

Stavanger, 17 March 2010

THE BOARD OF DIRECTORS OF STATOIL ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

ROY FRANKLIN

ELISABETH GRIEG

EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

JAKOB STAUSHOLM

MORTEN SVAAN

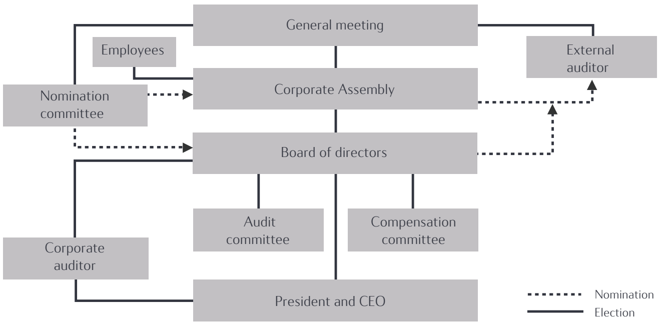
ELDAR SÆTRE
CHIEF FINANCIAL OFFICER

HELGE LUND
PRESIDENT AND CEO

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, being listed on the Oslo Stock Exchange, must annually report on compliance with the Norwegian Code of Practice for Corporate Governance from the Norwegian Corporate Governance Board (the "Code") and possible deviations from the Code must be explained. The Code covers 15 topics, and the statement shall cover each of these topics.

Statoil's board of directors has endorsed the Code and states that Statoil has complied with the Code throughout 2009.

Implementation of the code of practice

The board of directors places emphasis on maintaining a high standard of corporate governance in line with Norwegian and international standards of best practice.

The foundation for the Statoil group's governance structure is Norwegian law, with Statoil ASA being a Norwegian registered public limited liability company with its primary listing on the Oslo stock exchange. Our share is also listed on the New York Stock Exchange (NYSE) and we are subject to the listing requirements of NYSE and the requirements of the US Securities and Exchange Commission.

Good corporate governance is a prerequisite for a sound and sustainable company, and it is built on openness and equal treatment of our shareholders. Our governing structures and controls help ensure that we run our business in a justifiable and profitable manner to the benefit of our employees, shareholders, partners, customers and society. We continuously consider prevailing international standards of best practice in defining and exercising company policies as we believe there is a clear link between high quality governance and the creation of shareholder value.

At Statoil, the way we deliver is as important as what we deliver. The Statoil Book, which adresses all Statoil employees, sets the standards for our behaviour, our delivery and our leadership.

Our values guide the behaviour of all Statoil employees. Our corporate values are "courageous", "open", "hands-on" and "caring". Both our values and ethics are treated as an integral part of our business activities. Our Ethics Code of Conduct is further described in item 10.

Our governance and management system is further elaborated on our website at http://www.statoil.com/en/About/CorporateGovernance/Pages/default.aspx , where shareholders and other stakeholders can explore any topic of particular interest in more detail and easily navigate to related documentation.

Business

Statoil's objectives are set out in the articles of association and specified in our corporate strategy.

Statoil's objectives are defined in the company's articles of association. Statoil shall, either on its own or through participation in or together with other companies, carry out exploration, production, transportation, refining and marketing of petroleum and petroleum derived products, and other forms of energy, as well as other businesses.

Targets and strategies are adopted, both for Statoil as a group and for each business area, to support the company objective. Our corporate strategy has the following three main pillars:

- exploiting the full potential of the Norwegian continental shelf (NCS)
- establishing and developing growth positions outside the NCS, capitalising on our NCS and value chain competence and
- gradually developing a business within renewables based on synergies with our legacy business.

All within a framework of strict capital, cost and financial discipline.

We set absolute requirements for health, safety and the environment. Safe and efficient operations is our first priority. We aim to meet the world's growing demand for energy, while showing consideration for the environment and making an active effort to fight global climate change.

We are contributing to sustainable development in relation to our core activities in the countries in which we operate. We are committed to openness and anti-corruption, as well as respect for human rights and employee rights. That applies both to our own activities and to those parts of the value chain over which we have significant influence.

Full text of the articles of association can be found on our website at www.statoil.com/articlesofassociation.

Equity and dividends

The board of directors emphasises the importance of maintaining a predictable and attractive dividend level yet with equity capital at a level appropriate to Statoil's goals, strategy and risk profile.

Shareholders' equity

The group shareholders' equity at 31 December 2009 was NOK 198.3 billion, which represented 35% of the group's total assets. The board considers this satisfactory given the group's requirement for solidity in relation to its expressed goals, strategy and risk profile.

Dividend policy

The board of directors has decided to adjust the company's dividend policy in order to create a more predictable dividend level going forward.

It is Statoil's ambition to grow the annual cash dividend, measured in NOK per share in line with long term underlying earnings. When deciding the annual dividend level, the Board will take into consideration expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility.

In addition to cash dividend, Statoil might buy back shares as part of total distribution of capital to the shareholders

The direct link to the highly volatile IFRS net income has been removed, and the focus will be on growing the annual cash dividend per share in line with long- term underlying earnings. The new policy does not imply a change in the long-term dividend level, including potential share buy-backs, compared to the previous policy.

Purchase of own shares for use in the share savings programme

Since 2004, Statoil has had a share savings plan for its employees. The purpose of this plan is to strengthen the business culture and encourage loyalty through employees becoming part-owners of the company.

The annual general meeting of shareholders annually authorises the board to acquire Statoil shares in the market in order to continue implementation of the employees' share saving plan. The authorisation is valid until the next annual general meeting (AGM), no longer, however, than until 30 June the following year.

Equal treatment and close associates

Equal treatment of all shareholders is a core governance principle in Statoil.

Statoil has one class of shares, and each share confers one vote at the general meeting. The articles of association contain no restrictions on voting rights. The repurchase of own shares for use in the share savings programme for own employees (or, when applicable, for subsequent cancellation) is carried out through the Oslo stock exchange.

The Norwegian State as majority owner

The Norwegian state is the largest shareholder in Statoil with a 67% ownership interest, see more on our website at www.statoil.com/shareholders. The state's ownership in Statoil is managed by the Ministry of Petroleum and Energy.

It is declared Norwegian state ownership policy that the principles in the Code will be endorsed for state ownership, and the Norwegian Government has stated that it expects companies in which the state has ownership interests to follow the Code. The principles are presented in the state's yearly ownership report, and the report for 2008 can be found on the website: www.eierberetningen.nhd.no/2008/index.php?lang=english.

Contact between the State as owner and ourselves takes place in the same manner as for other institutional investors. In all matters in which the State acts in its capacity as shareholder, the exchange with the company is based on information that is available to all shareholders. We ensure that the objectives of any interaction between the Norwegian State and Statoil are based on distinction between the various roles that the Norwegian State encompasses.

The State has no appointed board members or members of the corporate assembly in Statoil. As majority shareholder, the State has appointed a member of Statoil's nomination committee.

Sale of the State's oil and gas

In accordance with Statoil's articles of association, Statoil has a duty to sell the State's oil and natural gas together with the group's own production..

The Norwegian state has a common ownership strategy aimed at maximising the total value of its ownership interests in Statoil and its own oil and gas interests. This is preserved in the owner's rules of procedure, which oblige Statoil, in its activities on the Norwegian continental shelf, to emphasise these overall interests in decisions that may be of significance to the implementation of the sales arrangements.

The state-owned oil company Petoro AS handles commercial matters relating to the Norwegian state's direct involvement in petroleum activities on the Norwegian continental shelf and pertaining activities.

Freely negotiable shares

Statoil's articles of association contain no form of restriction on negotiability of shares.

Statoil's primary listing is on the Oslo stock exchange. Our American Depository Rights (ADRs) are traded on the New York Stock Exchange. Each Statoil ADR represents one underlying ordinary share.

The shares and ADRs are freely negotiable.

General meetings

The general meeting of shareholders is Statoil's supreme corporate body that serves as a democratic and efficient forum for the interaction between the company's shareholders, board of directors and management.

The main framework as regards the convening and holding of an AGM in Statoil is as follows:

Pursuant to the company's articles of association, the AGM must be held by the end of June each year. Notice of the meeting and documentation for the AGM are published on Statoil's website at least 21 days prior to the meeting and consecutively sent by mail to all shareholders whose address is known within 21 days before the AGM. All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM.

Shareholders are entitled to have a proposal dealt with at the general meeting if the proposal has been submitted in writing to the board of directors in sufficient time to allow inclusion in the distributed notice of meeting. Shareholders who are prevented from attending may vote by proxy.

The deadline for registration for the AGM is the day before the AGM is due to take place.

The AGM is normally opened and chaired by the chair of the corporate assembly. If there is a dispute concerning individual matters and the chair of the corporate assembly belongs to one of the disputing parties or is for some other reason not perceived as being impartial, another person will be appointed to chair the AGM in order to ensure impartiality in relation to the matters to be considered. The AGM is conducted in Norwegian and translated simultaneously into English. As Statoil has a large number of shareholders with a wide geographical distribution, Statoil offers its shareholders the opportunity to follow the AGM by webcast with simultaneous translation into English.

At the AGM the following decisions are made:

- Election of the shareholders' representatives to the corporate assembly
- Election of the nomination committee (referred to as the election committee in the articles of association)
- Election of the external auditor and stipulation of the auditor's fee
- Approval of the board of directors' report, the financial statements and any dividend, proposed by the board of directors and recommended by the corporate assembly
- Any other matters listed in the notice convening the AGM.

All shares carry an equal right to vote at general meetings. Resolutions at AGMs are normally passed by simple majority. However, Norwegian company law requires a qualified majority for certain resolutions, including resolutions to waive preferential rights in connection with any share issue, approval of a merger or demerger, amendment of the articles of association or authorisation to increase or reduce the share capital. These matters require the approval of at least two-thirds of the aggregate number of votes cast as well as two-thirds of the share capital represented at the AGM.

Minutes from the AGM are made available on Statoil's website at www.statoil.com/agm immediately after the meeting.

In 2010, a proposal to revise the articles of association will be forwarded by the board for approval by the AGM. The revision, if approved, will allow distribution of documents to future AGMs at Statoil's website. A shareholder may nevertheless request that documents, which relate to matters to be dealt with by the AGM, are sent to him/her by regular mail.

Nomination committee

Pursuant to Statoil's articles of association, the nomination committee consists of four members who are shareholders or representatives of shareholders.

The nomination committee (in Statoil's articles of association referred to as the "election committee") is independent of both the board and the company's management.

The duties of the nomination committee are:

- to present recommendations to the general meeting of shareholders for the election of shareholder-elected members and deputy members of the corporate assembly and members of the nomination committee
- to present recommendations to the corporate assembly for the election of shareholder-elected members to the board of directors
- to present a proposal for the remuneration of members of the board of directors, the nomination committee and the corporate assembly.

The members of the nomination committee are elected by the general meeting of shareholders. Two of the members are elected from among the shareholder-elected members of the corporate assembly. Members of the nomination committee are normally elected for a term of two years.

More information on the members of Statoil ASA's nomination committee and the committee's rules of procedure can be found on our website at: www.statoil.com/electioncommittee.

Furthermore, an electronic mail-box for shareholders' proposals to the committee is accessible on our website at www.statoil.com/proposecandidate.

The nomination committee's rules of procedure are determined by the corporate assembly's shareholder-elected members, at the proposal of the board of directors.The rules of procedures state that the nomination committee will inter alia focus on the following criteria when preparing nominations: experience, competence, capacity, appropriate rotation, gender and independence.

The company covers the costs of the nomination committee.

The nomination committee held 16 meetings in 2009.

Corporate assembly, board of directors

The main duties of the corporate assembly and the board of directors are defined in the Norwegian company law.

Statoil's corporate assembly
Pursuant to Statoil's articles of association, our corporate assembly consists of 18 members 12 of whom, and four deputy members, are elected by the annual general meeting. Six members, with deputy members, and three observers are elected by and from among our employees. The corporate assembly elects its own chair and deputy chair from among its members.

Members of the corporate assembly are normally elected for a term of two years. Members of the board of directors and management cannot be members of the corporate assembly, but they are entitled to attend and to speak at meetings of the corporate assembly unless the corporate assembly decides otherwise in individual cases.

The duties of the corporate assembly are defined in section 6-37 of the Norwegian Public Limited Liability Companies Act.

Our corporate assembly held five meetings in 2009. The list of members of the corporate assembly is accessible on our website at www.statoil.com/corporateassembly.

Composition of the board of directors
In accordance with Norwegian law, the corporate assembly elects Statoil's board of directors. Pursuant to Statoil's articles of association, our board of directors consists of 10 members. Pursuant to Norwegian company law, the company's employees are entitled to elect three board members, with deputy members, while seven members of the board are elected by the shareholders. There are no deputy members for shareholder representatives on the board. The management is not represented on the board. Members of the board are normally elected for a term of two years.

A majority of the members of the board are deemed to be "independent" board members. One board member qualifies as "audit committee financial expert", as defined in the US Securities and Exchange Commission requirements. There are no board member service contracts that provide for benefits upon termination of office.

Each board member is presented on our website, including information about other directorships and offices held (current and recent), age, skills and experience, possible family connections within the company's governing bodies, information about loans from the company as well as share ownership in Statoil, see www.statoil.com/board.

The work of the board of directors

The board of directors of Statoil ASA is responsible for the overall management of the Statoil group, and for supervising the group's activities in general.

The board of directors handles matters of major importance or of an extraordinary nature. However, it may require management to refer any matter to it. The board of directors appoints the president and chief executive officer (CEO), and stipulates the job instructions, powers of attorney and terms and conditions of employment for the president and CEO.

The work of the board is based on rules of procedure that describe the board's responsibility, duties and administrative procedures. The rules of procedure also describe the duties of the CEO and his/her duties vis-à-vis the board of directors. The board's rules of procedures are accessible on our website at www.statoil.com/board. Besides the board of directors, members of the executive committee and other members of senior management attend board meetings by invitation.

Recurrent items on the board's yearly agenda are: corporate strategy issues, approval of business plans, approval of quarterly and annual results, management's monthly performance reporting, handling of the annual report, management compensation issues, CEO and top management leadership asssessment and succession planning, HSE (health, safety and environment) review, project status review, people and organisation strategy and priorities, enterprise risk evaluation and an annual review of the board's governing documentation. In addition, the board carries out an annual board evaluation, with input from various sources and with external facilitation.

The board of directors held 11 meetings in 2009 and meeting attendance was 94%.

Statoil's board of directors has two sub-committees:

The board's audit committee
The role of the audit committee is to assist in the exercise of the board's management and control responsibilities and to ensure that the group has an independent and effective external and internal auditing system. The duties of the audit committee include maintaining continuous contact with Statoil's elected auditor concerning the auditing of the company's accounts. The committee also supervises the implementation of and compliance with the group's ethical guidelines.

The audit committee assesses and makes a recommendation concerning the choice of external auditor, and it is responsible for ensuring that the external auditor meets the requirements set by the authorities in Norway and in other countries in which Statoil is listed on the stock exchange.

The board's audit committee held 6 meetings in 2009 and meeting attendance was 95%.

The instructions for the board's audit committee are available on our website at www.statoil.com/auditcommittee.

The board's compensation committee
The role of the compensation committee is to assist the board in its work on terms and conditions of employment for the chief executive, and on the philosophy, principles and strategy for the compensation of leading executives in Statoil.

The board's compensation committee held 8 meetings in 2009 and meeting attendance was 81%.

The instructions for the board's compensation committee are available on our website at www.statoil.com/compensationcommittee.

Risk management and internal control

The board of directors and management attach great importance to the quality of Statoil's risk management and control functions, and this is reflected in Statoil's management and control systems.

Risk management
Statoil manages risk to ensure safe operations and to achieve corporate objectives in compliance with prevailing requirements. The overall risk management approach includes continuous assessment and management of risk in all activities.

The company has a separate corporate risk committee which is chaired by the chief financial officer. The committee meets eight to ten times a year to consider and adopt the company's strategies for risk management. A thorough report on the company's risk management is presented in chapter 6 in the annual report on Form 20-F.

In Statoil, risk management is divided into three main categories:

- Strategic risks that are long-term market risks, and which are monitored by the company's corporate risk committee. The corporate risk committee gives advice and makes recommendations to the corporate executive committee based on strategic market risk policies.
- Tactical risks, which are short-term trading risks based on underlying exposures, are managed by the principle business segment line managers.
- Operational risks, which cover all major operational goals and underlying risk drivers, are managed as an integral part of line managers' resposibilities at all levels. In addition, insurable risks are handled by the captive insurance company operating in the Norwegian and international insurance markets.

Furthermore, Statoil has started implementation of business continuity management as a new risk handling strategy.

The management's report on internal control of financial reporting
The management of Statoil ASA is responsible for establishing and maintaining adequate internal control of financial reporting. Our internal control of financial reporting is a process designed under the supervision of the chief executive officer and chief financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Statoil's financial statements for external reporting purposes in accordance with International Financial Reporting Standards as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

The management has assessed the effectiveness of internal control of financial reporting based on the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, the management has determined that Statoil's internal control of financial reporting as of 31 December 2009 was effective.

Statoil's Ethics Code of Conduct and anti-corruption compliance programme
Our ability to create value is dependent on applying high ethical standards, and we are determined that Statoil shall be known for them. Ethics is treated as an integral part of our business activities. The group requires high ethical standards of everyone who acts on our behalf and will maintain an open dialogue on ethical issues, internally and externally.

Our Ethics Code of Conduct describes Statoil's commitment and requirements in connection with issues of an ethical nature that relate to business practice and personal conduct.

In our business activities, we will comply with applicable laws and regulations and act in an ethical, sustainable and socially responsible manner. Respect for human rights is an integral part of Statoil's values base.

The Ethics Code of Conduct is valid for everyone working for the Statoil group, including the members of the board of directors of Statoil and its subsidiaries. The Ethics Code of Conduct is available at www.statoil.com/ethics. Statoil's Anti-corruption Compliance Programme can also be found on the same webpage. In September 2009, Statoil's then Independent Compliance Consultant, retained by Statoil as part of the settlements with the US authorities in connection with the Horton matter, certified that Statoil "has implemented an anti-corruption compliance program that is appropriately designed and implemented to ensure compliance with the Foreign Corrupt Practises Act."

Business partners are also expected to have ethical standards that are consistent with Statoil's ethical requirements.

Statoil has a dedicated ethics helpline that may be used by employees who want to express concerns or seek advice regarding the legal and ethical conduct of our business.

Remuneration of the board of directors

Members of the board of directors receive remuneration in accordance with their individual roles.

The remuneration of the board is not dependent on results, and none of the shareholder-elected board members has a pension scheme or agreement on pay after termination of their office with the company.

Information about all remuneration paid to each member of the board of directors is presented in the parent company financial statements, note 6.

Remuneration of executive management

Statoil's remuneration policy is rooted in the company's personnel policy.

Statoil's remuneration policy
Statoil's remuneration policy is strongly linked to the company's value-based performance framework. Certain key principles have been adopted for the design of the company's remuneration concept. These principles pertain in general but they are applied differently to the different remuneration systems and job categories.

The remuneration concept shall;

- reflect our 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-term and long-term contributions and results.

Our rewards and recognition are designed to attract and retain people who perform, change and learn. The overall remuneration level and composition of the total reward reflect the national and international framework and business environment Statoil operates within.

The decision-making process
The decision-making process for changing remuneration policies and concepts and the determination of salaries and other remuneration of the corporate executive committee are in accordance with the provisions of the Norwegian Public Limited Liability Companies Act sections 5-6, 6-14, 6-16 a) and the board's Rules of Procedures as last amended on 31 July 2008.

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 pay arrangements
- Other benefits.

Fixed remuneration

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

Base salary

The base salary shall be competitive in the markets in which the company operates and shall reflect the individual's responsibility and performance. The evaluation of performance is based on fulfilment of certain pre-defined goals; refer to "Variable pay" below. The base salary is normally reviewed once a year.

Long-term incentive (LTI)

Statoil will carry on the established long-term incentive system for a limited number of senior managers, including the members of the corporate executive committee.

The LTI system is a fixed, monetary compensation calculated in per cent of the participant's base salary; ranging from 20 to 30% depending on the participant's position. The participant is obliged to buy Statoil shares in the market for the fixed LTI amount (after tax deduction) every year and to hold the shares for a lock-in period of three years.

The LTI and the annual variable pay system constitute a remuneration concept that focuses on both short-term and long-term goals and results. The LTI contributes to strengthening the common interests between the top management and the shareholders of Statoil.

Variable pay

The intention is to continue the company's variable pay concept in 2010. Based on performance, the chief executive officer is entitled to annual variable pay with a maximum potential of 50% of the fixed remuneration. The executive vice presidents have an equivalent variable pay scheme with a maximum potential of 40%.

In order to obtain an improved distribution of the annual variable pay, and to underpin a drive towards an even stronger performance, it has been decided to adjust the pay out level for performance at target level from 67 per cent to 50 per cent of the maximum potential.

Remuneration policies' effect on risk

The remuneration concept is an integrated part of our performance management system. An overarching principle is that there should be a close link between performance and remuneration.

Individual salary and annual variable pay reviews shall be based on the performance evaluation in our performance management system. However, participation in the LTI scheme and the size of the annual LTI element are not directly based on performance but linked to the executive's position level.

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 have two dimensions: delivery and behaviour, where delivery and behaviour are equally important and given equal weight. Delivery goals are established for each of the five perspectives: HSE, finance, operations, market, people and organisation. In each perspective, both longer-term strategic objectives and shorter-term targets and Key Performance Indicator (KPI) targets are set, as well as actions to be executed. Several of these actions will be risk-mitigating actions derived from strategic or operational risk assessments. Behaviour goals are based on Statoil's core values and leadership principles and address the behaviour required and expected in order to achieve our delivery goals

Performance evaluation is a holistic evaluation combining measurement and assessment of performance against both delivery and behaviour goals. Hence, sound judgement and hindsight information are applied before final conclusions are drawn. For instance, measured KPI results are reviewed in relation to their strategic contribution, sustainability and significant changes in assumptions.

This balanced scorecard approach, with goals defined in both the delivery and behaviour dimension, and a holistic performance evaluation, should significantly reduce the risk that our remuneration policies are likely to have a material adverse effect.

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

Statement regarding remuneration
The board's statement regarding all remuneration of the corporate executive committee, as well as information about all remuneration paid to each member of the executive committee, is presented in the parent company financial statements, note 6.

Information and communications

Statoil has established guidelines for the company's reporting of financial and other information based on openness and taking into account the requirement for equal treatment of all participants in the securities market.

The purpose of these guidelines is to ensure the dissemination of timely and correct information about the company to our shareholders and society in general.

A financial calendar and shareholder information is published at www.statoil.com/calendar.

The investor relations corporate staff function is responsible for coordinating the group's communication with capital markets and for relations between Statoil and existing and potential investors in the company. Investor relations is responsible for distributing and registering information in accordance with the legislation and regulations that apply where Statoil securities are listed. Investor relations reports directly to the chief financial officer.

The group's management holds regular presentations for investors and analysts. The company's quarterly presentations are broadcasted live on the internet. The pertaining reports are made available together with other relevant information at www.statoil.com/investor.

Take-overs

Statoil's articles of association do not set limits on share acquisitions.

Statoil's board of directors endorses the principles concerning equal treatment of all shareholders, and is obliged to act professionally and in accordance with the applicable principles for good corporate governance if a situation were to arise in which this principle in the Code of Practice were put to the test.

Auditor

Pursuant to its instructions, the board's audit committee is responsible for ensuring that the company group is subject to an independent and effective audit.

Our independent registered public accounting firm (independent auditor) is independent in relation to Statoil and is appointed by the general meeting of shareholders. The independent auditor's fee must be approved by the general meeting of shareholders.

Pursuant to the instruction for the board's audit committee (audit committee) approved by the board of directors, the audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

Every year, the independent auditor presents a plan for the audit committee for the execution of the independent auditor's work.

The independent auditor is present at the board meeting that deals with the preparation of the annual accounts.

The independent auditor participates in meetings with the audit committee at which the internal control system is discussed.

When evaluating the independent auditor, emphasis is placed on the firm's competence, capacity, local and international availability, and the size of the fee.

The audit committee evaluates and makes a recommendation regarding the choice of independent auditor, and it is responsible for ensuring that the independent auditor meets the requirements in Norway and in the countries where Statoil is listed. The independent auditor is subject to the provisions of US securities legislation, which stipulate that a responsible partner may not lead the engagement for more than five consecutive years.

The audit committee considers all reports from the independent auditor before they are considered by the board of directors. The audit committee holds regular meetings with the independent auditor without the company's management being present.

Audit committee pre-approval policies and procedures

In the instruction for the audit committee, the board of directors has delegated to the audit committee authority to pre-approve assignments to be performed by the independent auditor. The audit committee has issued guidelines for the management's pre-approval of assignments to be performed by the independent auditor.

All services provided by the independent auditor must be pre-approved by the audit committee. Provided that the suggested types of services are permissible under SEC guidelines, pre-approval is usually granted at a regular audit committee meeting. The chair of the audit committee has been authorised to pre-approve services in accordance with policies established by the audit committee, specifying in detail the types of services that qualify, and provided that any services pre-approved in this manner are presented to the full audit committee at its next meeting. Some pre-approvals may therefore be granted by the chair of the audit committee if an urgent reply is deemed necessary.

In the annual consolidated financial statements and in the parent company's financial statements, the independent auditor's remuneration is split between the audit fee and audit-related and other services fees. In the presentation for the annual general meeting of shareholders, the chair presents the split between the audit fee and audit-related and other services fees.

Consolidated Financial Statements

CONSOLIDATED STATEMENT OF INCOME

(in NOK million)	Note	2009	For the year ended 31 December 2008	2007
REVENUES AND OTHER INCOME				
Revenues		**462,292**	651,977	521,665
Net income from associated companies	15	**1,778**	1,283	609
Other income		**1,363**	2,760	523
Total revenues and other income	5	**465,433**	656,020	522,797
OPERATING EXPENSES				
Purchases [net of inventory variation]		**(205,870)**	(329,182)	(260,396)
Operating expenses		**(56,860)**	(59,349)	(60,318)
Selling, general and administrative expenses		**(10,321)**	(10,964)	(14,174)
Depreciation, amortisation and net impairment losses	13	**(54,056)**	(42,996)	(39,372)
Exploration expenses		**(16,686)**	(14,697)	(11,333)
Total operating expenses		**(343,793)**	(457,188)	(385,593)
Net operating income	5	**121,640**	198,832	137,204
FINANCIAL ITEMS				
Net foreign exchange gains (losses)		**1,993**	(32,563)	10,043
Interest income and other financial items		**3,708**	12,207	2,305
Interest and other finance expenses		**(12,451)**	1,991	(2,741)
Net financial items	10	**(6,750)**	(18,365)	9,607
Income before tax		**114,890**	180,467	146,811
Income tax	11	**(97,175)**	(137,197)	(102,170)
Net income		**17,715**	43,270	44,641
Attributable to:				
Equity holders of the company		**18,313**	43,265	44,096
Non-controlling interest (Minority interest)		**(598)**	5	545
		17,715	43,270	44,641
Earnings per share for income attributable to equity holders of the company - basic and diluted	12	**5.75**	13.58	13.80

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in NOK million)	2009	For the year ended 31 December 2008	2007
Net income	17,715	43,270	44,641
Foreign currency translation differences	(13,637)	30,880	(9,858)
Actuarial gains (losses) on employee retirement benefit plans	3,191	(7,945)	74
Change in fair value of available for sale financial assets	(66)	(1,362)	926
Income tax on income and expense recognised directly in OCI	(742)	(802)	(175)
Other comprehensive income (OCI)	(11,254)	20,771	(9,033)
Total comprehensive income	6,461	64,041	35,608
Attributable to:			
Equity holders of the parent company	7,059	64,036	35,063
Non-controlling interest	(598)	5	545
	6,461	64,041	35,608

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2009	At 31 December 2008 (restated)	At 1 January 2008 (restated)
ASSETS				
Non-current assets				
Property, plant and equipment	13	340,835	329,841	278,352
Intangible assets	14	54,253	66,036	44,850
Investments in associated companies	15	10,056	12,640	8,421
Deferred tax assets	11	1,960	1,302	793
Pension assets	23	2,694	30	1,622
Financial investments	16	13,267	16,465	15,266
Derivative financial instruments	30	17,644	21,282	12,768
Financial receivables	16	5,747	4,914	3,515
Total non-current assets		446,456	452,510	365,587
Current assets				
Inventories	17	20,196	15,151	17,696
Trade and other receivables	18	58,895	69,931	69,378
Current tax receivable		179	3,840	0
Derivative financial instruments	30	5,369	9,366	8,802
Financial investments	19	7,022	9,747	3,359
Cash and cash equivalents	20	24,723	18,638	18,264
Total current assets		116,384	126,673	117,499
TOTAL ASSETS		562,840	579,183	483,086

CONSOLIDATED BALANCE SHEET

(in NOK million)	Note	At 31 December 2009	At 31 December 2008 (restated)	At 1 January 2008 (restated)
EQUITY AND LIABILITIES				
Equity				
Share capital		**7,972**	7,972	7,972
Treasury shares		**(15)**	(9)	(6)
Additional paid-in capital		**41,732**	41,450	41,370
Additional paid-in capital related to treasury shares		**(847)**	(586)	(359)
Retained earnings		**145,909**	147,998	140,909
Other reserves		**3,568**	17,254	(12,611)
Statoil shareholders' equity		**198,319**	214,079	177,275
Non-controlling interest (Minority interest)		**1,799**	1,976	1,792
Total equity		**200,118**	216,055	179,067
Non-current liabilities				
Financial liabilities	22	**95,962**	54,606	44,374
Derivative financial instruments		**1,657**	1,617	27
Deferred tax liabilities	11	**76,322**	68,144	67,477
Pension liabilities	23	**21,142**	25,538	19,092
Assets retirement obligations, other provisions and other liabilities	24	**55,834**	54,359	43,845
Total non-current liabilities		**250,917**	204,264	174,815
Current liabilities				
Trade and other payables	25	**59,801**	61,200	64,624
Current tax payable		**40,994**	57,074	50,941
Financial liabilities	26	**8,150**	20,695	6,166
Derivative financial instruments	30	**2,860**	19,895	7,473
Total current liabilities		**111,805**	158,864	129,204
Total liabilities		**362,722**	363,128	304,019
TOTAL EQUITY AND LIABILITIES		**562,840**	579,183	483,086

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves: Available for sale financial assets	Other reserves: Currency translation adjustments	Statoil share-holders' equity	Non-controlling interest	Total
At 1 January 2007	3,208,805,951	8,022	(54)	44,684	(3,605)	122,153	450	(3,817)	167,833	1,574	169,407
Net income for the period						44,096			44,096	545	44,641
Income and expense recognised directly in OCI						211	614	(9,858)	(9,033)		(9,033)
Total recognised income and expense for the period*											35,608
Dividend paid						(25,694)			(25,694)		(25,694)
Cash distributions (to) from non-controlling interest										(327)	(327)
Merger related adjustments						143			143		143
Effectuation of annulment	(20,158,848)	(50)	50	(3,426)	3,426				0		0
Equity settled share based payments (net of allocated shares)				112					112		112
Treasury shares purchased (net of allocated shares)			(2)		(180)				(182)		(182)
At 31 December 2007	3,188,647,103	7,972	(6)	41,370	(359)	140,909	1,064	(13,675)	177,275	1,792	179,067
Net income for the period						43,265			43,265	5	43,270
Income and expense recognised directly in OCI						(9,094)	(1,015)	30,880	20,771		20,771
Total recognised income and expense for the period*											64,041
Dividend paid						(27,082)			(27,082)		(27,082)
Cash distributions (to) from non-controlling interest										179	179
Equity settled share based payments (net of allocated shares)				80					80		80
Treasury shares purchased (net of allocated shares)			(3)		(227)				(230)		(230)
At 31 December 2008	3,188,647,103	7,972	(9)	41,450	(586)	147,998	49	17,205	214,079	1,976	216,055

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves: Available for sale financial assets	Other reserves: Currency translation adjustments	Statoil share-holders' equity	Non-controlling interest	Total
At 31 December 2008	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
Income and expense recognised directly in OCI						2,432	(49)	(13,637)	(11,254)		(11,254)
Total recognised income and expense for the period*											6,461
Dividend paid						(23,085)			(23,085)		(23,085)
Cash distributions (to) from non-controlling interest										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

* For detailed information, see Consolidated statement of comprehensive income

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	2009	For the year ended 31 December 2008 (restated)	2007 (restated)
OPERATING ACTIVITIES			
Income before tax	114,890	180,467	146,811
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortisation and impairment losses	54,056	42,996	39,372
Exploration expenditures written off	6,998	3,872	1,660
(Gains) losses on foreign currency transactions and balances	6,512	15,243	(559)
(Gains) losses on sales of assets and other items	(526)	(2,704)	(188)
Termination benefits	0	0	8,633
Changes in working capital (other than cash and cash equivalents):			
· (Increase) decrease in inventories	(5,045)	2,470	(2,434)
· (Increase) decrease in trade and other receivables	11,036	(1,129)	(6,493)
· (Increase) decrease in net current financial derivative instruments	(13,038)	11,858	4,277
· (Increase) decrease in current financial investments	2,725	(6,388)	(2,327)
· Increase (decrease) in trade and other payables	(1,365)	(5,466)	10,447
Taxes paid	(100,473)	(139,604)	(102,422)
(Increase) decrease in non-current items related to operating activities	(2,769)	918	(2,851)
Cash flows provided by operating activities	73,001	102,533	93,926
INVESTING ACTIVITIES			
Additions through business combinations	0	(13,120)	0
Additions to property, plant and equipment	(67,152)	(58,529)	(63,785)
Exploration expenditures capitalised	(7,203)	(6,821)	(4,569)
Changes/Additions to other intangibles	(795)	(10,828)	(7,186)
Changes in long-term loans granted and other long-term items	(1,636)	(1,910)	(652)
Proceeds from sale of assets	1,430	5,371	1,080
Cash flows used in investing activities	(75,356)	(85,837)	(75,112)

CONSOLIDATED STATEMENT OF CASH FLOWS

(in NOK million)	2009	For the year ended 31 December 2008 (restated)	2007 (restated)
FINANCING ACTIVITIES			
New long-term borrowings	46,318	2,596	1,723
Repayment of long-term borrowings	(4,905)	(2,864)	(2,876)
Distribution (to)/from non-controlling interests	421	179	(327)
Dividend paid *	(23,085)	(27,082)	(25,695)
Treasury shares purchased	(343)	(308)	(217)
Norsk Hydro ASA merger balance	0	0	18,687
Net short-term borrowings, bank overdrafts and other **	(7,115)	10,450	797
Cash flows provided by (used in) financing activities	11,291	(17,029)	(7,908)
Net increase (decrease) in cash and cash equivalents	8,936	(333)	10,906
Effect of exchange rate changes on cash and cash equivalents	(2,851)	707	(160)
Cash and cash equivalents at the beginning of the period	18,638	18,264	7,518
Cash and cash equivalents at the end of the period	24,723	18,638	18,264
Interest paid	2,912	2,771	3,709
Interest received	3,962	4,544	2,256

* Dividend paid in 2007 includes NOK 6.1 billion charged to Hydro Petroleum from Norsk Hydro ASA under the terms of the merger plan.

** Regarding redemption of shares held by the state, Statoil has paid the state NOK 2.4 billion in 2007.

1 Organisation

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

Effective 1 October 2007, Statoil ASA merged with the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum), and the company's name changed to StatoilHydro ASA. As of 1 November 2009 the name was changed back to Statoil ASA. 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.

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

Statoil's oil and gas activities and net assets on the Norwegian Continental Shelf (NCS) were until 31 December 2008 owned by Statoil ASA and by Statoil Petroleum AS. With effect from 1 January 2009, Statoil ASA transferred the ownership of its NCS net assets to Statoil Petroleum AS, a 100% owned operating subsidiary. Following the transfer, all NCS net assets are owned by Statoil Petroleum AS. As a result of this group internal reorganisation, the nature of the parent company Statoil ASA's operations and transactions were changed so that its functional currency also changed from NOK to USD effective as of the same date and with prospective effect. The functional currency of Statoil Petroleum AS has not changed and remains NOK. The presentation currency for the Statoil group remains NOK.

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 the group 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 statements 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 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 in issue, not yet adopted
At the date of these financial statements the following standards and interpretations were in issue but not yet effective:

The revised version of IFRS 3 Business Combinations, issued in January 2008, covers definition, identification, accounting for and disclosure of business combinations, inclusive of business combinations achieved in stages. It will be applicable to business combinations occurring in annual periods beginning on or after 1 July 2009. There is not expected to be any material effect on Statoil's reported net income or equity upon adoption of the revised standard on 1 January 2010.

The amended version of IAS 27 Consolidated and Separate Financial Statements, issued in January 2008, primarily covers amendments related to accounting for non-controlling interests and the loss of control of a subsidiary, and is effective for annual periods beginning on or after 1 July 2009. There is not expected to be any material effect on Statoil's reported net income or equity on adoption of the amendment on 1 January 2010.

The Improvements to IFRS 2009 issued in April 2009 include amendments effective for accounting periods beginning on or after 1 July 2009 or 1 January 2010 respectively, depending on the standard involved, and include amendments to a number of accounting standards. None of the amendments are expected to significantly impact Statoil's net profit, equity or classifications in the balance sheet or statement of income.

IFRS 9 Financial Instruments, issued in November 2009, covers the classification and measurement of financial assets and will be effective from 1 January 2013. IFRS 9 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 the potential impact of this standard.

The revised IAS 24 Related Party Disclosures issued in November 2009 defines the term related party and establishes disclosure requirements to be applied, and will be effective from 1 January 2011. Statoil will comply with the revised standard and provide relevant disclosure upon adoption as applicable.

The amendment to IFRIC 14 Prepayments of a Minimum Funding Requirement issued in November 2009 and effective as of 1 January 2011 is not expected to have any material effect on Statoil's reported net income or equity on adoption.

The amendment to IAS 32 Classification of Rights Issues issued in November 2009 and effective from accounting periods beginning 1 February 2010 or later, the amendment to IFRS 2 Group Cash-settled Share-based Payment Transactions issued in July 2009 and effective from 1 January 2010 and IFRIC 19 Extinguishing Financial Liabilities with Equity Instruments issued in November 2009 and effective for annual periods beginning on or after 1 July 2010 are currently not relevant for Statoil.

Significant changes in accounting policies

With effect from 1 January 2009 Statoil adopted amendments to IAS 1 Presentation of Financial Statements issued in September 2007. The Statement of recognised income and expenses has been replaced with the Consolidated statement of comprehensive income and the Consolidated statement of changes in equity, which Statoil previously presented in the Equity note. The Consolidated statement of changes in equity shows changes in non-controlling interests separately.

Based on amendments to IAS 1 Presentation of Financial Statements included in the improvements to IFRSs effective 1 January 2009, Statoil in 2009 reclassified certain instruments in the IAS 39 Financial Instruments: Recognition and Measurement related held for trading category from current assets or liabilities to non-current assets or liabilities. Statoil's principle as applied in the balance sheet for 31 December 2009 is described in relevant paragraphs below, while information on reclassified amounts is included in note 30. The policy change has been applied retrospectively by adjusting the balance sheets for 31 December 2008 and 1 January 2008 respectively, and in consequence a balance sheet as at 1 January 2008 has been included in these financial statements.

As of 31 December 2009 Statoil adopted revisions to the oil and gas estimation and disclosure requirements. For additional information see "Critical accounting judgements and key sources of estimation uncertainty; Proved oil and gas reserves".

Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of Statoil ASA and its subsidiaries. Subsidiaries are entities controlled by the company. 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, associates and joint venture entities

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 the equity method. 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 group statements 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 statement of income and balance sheet.

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 date of the transaction. 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 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 consolidated financial statements, the statements of income and balance sheets of each entity are translated into Norwegian kroner (NOK), which is the presentation currency of the consolidated financial statements. 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 average monthly foreign exchange rates, which approximates the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are recognised separately in Other comprehensive income.

Business combinations and goodwill
In order to meet the criteria for a business combination the acquired asset or group of assets must constitute a business (an integrated set of activities and assets conducted and managed for the purpose of providing a return to investors). This requires judgment to be applied on a case by case basis as to whether the acquisition meets the definition of a business combination. Acquisitions of exploration and evaluation licences are assessed under the relevant criteria to establish whether the transaction represents a business combination or an asset purchase. Acquisitions of 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, have been accounted for using the purchase 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. Any excess of the cost of purchase over the net fair value of the identifiable assets acquired is recognised as goodwill.

Goodwill on acquisition is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included in income from jointly controlled entities and associates.

Revenue recognition
Revenues associated with sale and transportation of crude oil, natural gas, petroleum and chemical products and other merchandise are recognised when title and risk pass to the customer, which is normally 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 recorded 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.

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 statements 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 SDFI oil production are recorded as purchases [net of inventory variation] and revenue, respectively. Statoil 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 recorded net in Statoil'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 the group. The accounting policy for share-based payments and pension obligations is 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 expense, and recorded as an equity transaction (included in additional paid-in capital).

Research and development
Statoil undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. Statoil's share of the licence holders' funding and the total costs of the unfunded projects are development costs that 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 directly 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 recorded 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 recognized based on future taxable profits, 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, 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 expenditures are incurred. Uplift benefit is recorded 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 derecognition or tested for impairment. Geological and geophysical costs and other exploration expenditures are expensed as incurred.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which Statoil has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are reflected in the financial statements as and when the exploration and development work progresses. Exploration and evaluation asset dispositions (farm-out arrangements) are accounted for on a historical cost basis with no gain or loss recognition.

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 a major capital expenditure can be justified, 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 moreover 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 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 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. 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 exchange transaction lacks commercial substance or 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 and are depreciated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production (E&P) assets Statoil has established separate depreciation categories for platforms, pipelines, and wells as a minimum.

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 Statoil assumes substantially all the risks and rewards of the ownership are reflected as finance leases within Property, plant and equipment and Financial liabilities, respectively. Assets under development for finance lease purposes, and for which Statoil carries substantially all the risk in the construction period, are recorded 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 income 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 balance sheet as Property, plant and equipment and Financial 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 leases, which imply the right to use a specific asset for a period of time, and capacity contracts, which confer on the group 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 group to qualify as leases for accounting purposes. Capacity payments are reflected as Operating expenses in the Consolidated statements 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.

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. Such an asset is subject to impairment testing when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount (or at least on an annual basis), and is 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 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, as well as through the amortisation process. 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 financial assets are carried on the balance sheet at fair value, 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 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 recognized in the category financial instruments at fair value through profit or loss, either as held for trading or through the group'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 represent derivative 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 and for which there is no plan of realization 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 instrument 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 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 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). Statoil considers post-tax calculations sufficiently objective and consistently applicable across the various tax regimes, while still for all significant purposes leading to the same conclusion that application of pre tax rates in accordance with IAS 36 Impairment of assets would have yielded.

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 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 recorded 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, with the amount of the loss recognised in the statement of income. Any subsequent reversal of an impairment loss correspondingly also is recognised in the statement of income.

If an AFS financial asset is impaired, i.e. 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 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 the 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 derivative 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.

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. 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 other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of host contracts and the host contracts are not carried at fair value. 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. 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.

Net 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. Following the parent company Statoil ASA's change in functional currency as of 1 January 2009, the significant part of the group's pension obligations will be payable in a foreign currency (ie. 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.

Onerous contracts

Statoil recognises as provisions the 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)

Liabilities for decommissioning costs are recognised when Statoil has an obligation 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 decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. At the time of the obligating event, a decommissioning liability is recognised and classified as Asset retirement obligations, other provisions and other liabilities. 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 recorded. For retail outlets, decommissioning provisions are estimated on a portfolio basis.

When a liability for decommissioning cost is recognised, a corresponding amount is recorded 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

Observable prices quoted in an active market 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 in all significant aspects 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 commodity based futures, exchange traded option contracts, 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. In the valuation techniques the group also takes into consideration counterparty and own credit risk. This is either reflected in the discount rate used, or through direct adjustments to the calculated cash flows. Consequently, where Statoil records 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 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 assessed whether the risk and reward of the ownership of the goods had been transferred from the SDFI to Statoil.

As also described above, Statoil 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 recorded 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.

Method of accounting applied for the Hydro Petroleum merger
The merger between former Statoil ASA and Hydro Petroleum in 2007 was accounted for using the carrying amounts of the assets and liabilities. When making this judgement Statoil considered firstly whether the former Statoil ASA and Hydro Petroleum were under the common control of the Norwegian State, and secondly, given the conclusion that both entities were under the control of the Norwegian State, assessed what method of accounting would provide the most meaningful portrayal of the merger for accounting purposes. Statoil concluded that such a reorganisation would be best presented using the carrying amounts of assets and liabilities, and it is presented in the financial statements for all periods presented as if the companies had always been combined.

Key sources of estimation uncertainty
The preparation of consolidated financial statements requires that management make estimates and assumptions that affect reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the result of which form the basis of making the judgements about carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. The estimates and underlying assumptions are reviewed on an ongoing basis considering the current and expected future market conditions.

Statoil is exposed to a number of underlying economic factors, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, interest rates as well as financial instruments with fair values derived from changes in these factors, which affect the overall results. In addition, Statoil's results are influenced by the level of production, which in the short term may be influenced by for instance maintenance programmes. In the long term, the results are impacted by the success of exploration and field development activities.

The matters described below are considered to be the most important in understanding the key sources of estimation uncertainty that are involved in preparing these financial statements and the uncertainties that could most significantly impact the amounts reported on the results of operations, financial position and cash flows.

Proved oil and gas reserves. 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. The SEC revised Rule 4-10 of Regulation S-X and changed a number of oil and gas reserve estimation requirements effective for the year ending 31 December 2009. This required, on a prospective basis, the use of a price based on a 12-month average for reserve estimation instead of a single end-of-year price and allows for non-traditional sources such as bitumen extracted from oil sands to be included as reserves. The Financial Accounting Standards Board (FASB) also aligned the requirements for supplemental oil and gas disclosures with the changes made by the SEC. Statoil estimates that implementation of the revisions had an immaterial impact on proved reserves as of 31 December 2009 and will have an immaterial impact on unit of production depreciation starting in 2010. However, the comparability of disclosures between years is impacted by the new requirements.

Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction recovery and processing yield factors and installed plant operating capacity. For future development projects, proved reserves estimates are included only where there is a significant commitment to project funding and execution and when relevant governmental and regulatory approvals have been secured or are reasonably certain to be secured. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. An independent third party has evaluated Statoil's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Unless evidence indicates that renewal is reasonably certain, estimates of economically producible reserves only reflect the period before the contracts providing the right to operate expire. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence within a reasonable time. Future changes in proved oil and gas reserves, for instance as a result of changes in prices, could have a material impact on unit of production rates used for depreciation and amortisation.

Expected oil and gas reserves. Expected oil and gas reserves have been estimated by internal experts on the basis of industry standards and are used for impairment testing purposes and for calculation of asset retirement obligations. Reserves estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbons volumes, the production, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. Future changes in expected oil and gas reserves, for instance as a result of changes in prices, could have a material impact on asset retirement obligations, as well as for the impairment testing of upstream assets, which could have a material effect on operating income as a result of changed impairment charges.

Exploration and leasehold acquisition costs. Statoil capitalises the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. Statoil also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgments as to whether these expenditures should remain capitalised or written down due to impairment losses in the period may materially affect the operating income for the period.

Impairment/reversal of impairment. Statoil has significant investments in property, plant and equipment and intangible assets. Changes in the circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired requiring the book value to be written down to its recoverable amount. Impairments are reversed if conditions for impairment are no longer present. Evaluating whether an asset is impaired or if an impairment should be reversed requires a high degree of judgement and may to a large extent depend upon the selection of key assumptions about the future.

Unproved oil and gas properties are assessed for impairment when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount and at least annually. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Subsequent to the initial evaluation phase for a well it will be considered a trigger for impairment testing of a well if no development decision is planned for the near future, and there moreover is no concrete plan for future drilling in the licence. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

Estimating recoverable amounts involves complexity in estimating relevant future cash flows, based on assumptions about the future, and discounted to their present value. Impairment testing requires long-term assumptions to be made concerning a number of often volatile economic factors such as future market prices, refinery margins, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Impairment testing frequently also requires judgement to be applied as regards applicable 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 recorded 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 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 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 Business combinations

In 2008 Statoil increased the interest in the Peregrino heavy-oil field offshore Brazil from 50% to 100%, after closing the deal to acquire Anadarko's 50% stake on 10 December 2008. Statoil paid a cash consideration of USD 1.8 billion, including expenditures incurred in the period 1 January to 10 December 2008, for 100% of the shares in Anadarko's wholly owned company Anadarko Petroleo Ltda and Anadarko's 50% share of the company South Atlantic Holding BV. Conditional on future oil prices above pre-defined threshold levels, Statoil will pay an additional maximum pre-tax amount of USD 0.3 billion to be earned by 2020, related to the Peregrino field. The value of the contingent consideration element at the time of closing the deal, estimated to USD 0.2 billion, has been recognised as part of the acquisition price. The Peregrino acquisition has been assessed to constitute a business combination under IFRS 3 and changes in the fair value of the contingent consideration element will be recorded as an adjustment to the book value of the assets acquired. The transaction was recorded in the segment International Exploration and Production.

4 Asset acquisitions and disposals

In November 2008 Statoil acquired a 32.5% interest in the Marcellus shale gas acreage from Chesapeake Appalachia, L.L.C. The Marcellus shale gas acreage covers 1.8 million net acres (7,300 square kilometres) in the Appalachia region of the Northeastern USA. Statoil paid a cash consideration of USD 1.3 billion and are paying an additional USD 2.1 billion in the form of funding of 75% of Chesapeake's expenditures for drilling and completion of wells during the period 2009 to 2012. The Marcellus assets are in the exploration and evaluation phase and the funding of Chesapeake's expenditures will be recorded in the financial statements at the time the expenditures for the wells are incurred. The transaction was recorded in the segment International Exploration and Production.

In February 2008 Statoil's participation in the Petrocedeño project (former Sincor project) was reduced from 15% to 9.677% as a result of the transformation of the Sincor project into the incorporated joint venture Petrocedeño, S.A., which has 60% participation by the Venezuelan state through its wholly owned company Petroleos de Venezuela, S.A. The Petrocedeño project involves the exploitation of extra heavy crude oil from the reservoirs in the Orinoco Belt offshore Venezuela. An accounting gain from the reduction of the participation interest was recognised in the Consolidated statements of income in 2008 by NOK 1.1 billion net of tax. The transaction was recorded in the segment International Exploration and Production. The remaining interest in Petrocedeño is reflected in the Consolidated financial statements under the equity method, while the previous interest in the Sincor project was accounted for as a jointly controlled asset consolidated on a line-by-line basis.

In the second quarter of 2007 Statoil acquired all shares of North American Oil Sands Corporation (NAOSC) for a consideration of CAD 2.2 billion. The principle asset in the acquisition was the 257,200 acres (1,110 square kilometres) of oil sands leases that NAOSC operates, located in the Athabasca region of Alberta, northeast of Edmonton. The transaction was recorded in the segment International Exploration and Production.

In the first quarter of 2007 Statoil acquired two of Anadarko Petroleum Corporation's US Gulf of Mexico discoveries and one prospect at a cost of USD 0.9 billion. The assets are located in the Greater Tahiti and Walker Ridge areas. As part of the transaction Statoil acquired an additional 15% working interest in the Big Foot discovery and has now a 27.5% working interest. The transaction was recorded in the segment International Exploration and Production.

5 Segments

Operating segments
Statoil manages its operations in four operating segments; Exploration and Production Norway, International Exploration and Production, Natural Gas and Manufacturing and Marketing. The Exploration and Production Norway and International Exploration and Production segments explore for, develop and produce crude oil and natural gas, and extract natural gas liquids. The Natural Gas segment transports and markets natural gas and natural gas products. Manufacturing and Marketing is responsible for petroleum refining operations and the marketing of crude oil and refined petroleum products except for natural gas and natural gas products.

The "Other" section consists of the activities of Corporate services, Corporate center, Group Finance, Technology & New energy and Projects. The "Eliminations" section encompasses 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.

Operating segments align with internal management reporting to the company's chief operating decision maker, defined as the Corporate Excecutive Committee (CEC). The operating segments are determined based on differences in the nature of their operations, products, services and geographical location of the activity. The measure of segment profit is Net operating income. Financial items and tax expense are not allocated to the operating segments. The measurement basis for the net operating income for each operating segment follows the accounting principles used in the financial statements as described in note 2 Significant accounting policies.

Segment data for the years ended 31 December, 2009, 2008 and 2007 is presented below:

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2009							
Revenues third party and Other income	4,153	12,301	96,973	348,941	1,287	0	463,655
Revenues inter-segment	154,431	28,459	1,241	2,014	2,295	(188,440)	0
Net income from associated companies	79	1,075	399	280	(55)	0	1,778
Total revenues and other income	158,663	41,835	98,613	351,235	3,527	(188,440)	465,433
Net operating income	104,318	2,599	18,488	(541)	(1,146)	(2,078)	121,640
Significant non-cash items recognised in segment profit or loss							
- Depreciation and amortisation	25,653	16,231	1,778	2,390	687	0	46,739
- Impairment losses	0	873	1,001	5,369	74	0	7,317
- Inventory valuation	0	0	(24)	(5,171)	0	1,377	(3,818)
- Commodity based derivatives	(1,781)	0	(2,814)	1,072	(122)	0	(3,645)
- Exploration expenditure written off	1,177	5,821	0	0	0	0	6,998
Investments in associated companies	214	4,962	2,829	917	1,134	0	10,056
Other segment non-current assets	175,998	152,678	34,797	28,587	3,028	0	395,088
Non-current assets, not allocated to segments*							41,312
Total non-current assets							446,456
Additions to PP&E and intangible assets**	34,875	39,354	2,528	7,618	1,340	0	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 abandonment and removal obligations.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2008							
Revenues third party and Other income	2,879	10,289	108,704	530,165	2,700	0	654,737
Revenues inter-segment	216,882	35,031	1,882	966	2,212	(256,973)	0
Net income from associated companies	82	809	225	216	(49)	0	1,283
Total revenues and other income	219,843	46,129	110,811	531,347	4,863	(256,973)	656,020
Net operating income	166,907	12,784	12,541	4,548	(731)	2,783	198,832
Significant non-cash items recognised in segment profit or loss:							
- Depreciation and amortisation	24,043	11,619	2,310	2,117	596	0	40,685
- Impairment losses	0	2,063	0	0	248	0	2,311
- Inventory valuation	0	0	24	5,203	0	(1,377)	3,850
- Commodity based derivatives	(109)	0	(1,341)	(1,306)	(37)	0	(2,793)
- Exploration expenditure written off	749	2,957	0	0	0	0	3,706
Investments in associated companies	149	6,114	4,898	1,063	416	0	12,640
Other segment non-current assets	165,493	160,580	35,735	34,420	3,854	0	400,082
Non-current assets, not allocated to segments*							20,889
Total non-current assets							433,611
Additions to PP&E and intangible assets**	34,941	48,694	2,041	8,488	1,256	0	95,420

* Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

** Excluding movements due to changes in abandonment and removal obligations.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2007							
Revenues third party and Other income	5,925	13,483	72,447	427,342	2,851	140	522,188
Revenues inter-segment	173,259	27,746	927	468	1,600	(204,000)	0
Net income from associated companies	60	372	60	233	(116)	0	609
Total revenues and other income	179,244	41,601	73,434	428,043	4,335	(203,860)	522,797
Net operating income	123,150	12,161	1,562	3,776	(2,260)	(1,185)	137,204
Significant non-cash items recognised in segment profit or loss:							
- Depreciation and amortisation	23,030	9,857	1,595	1,896	564	0	36,942
- Impairment losses	0	1,246	250	937	(3)	0	2,430
- Pension costs*	5,300	738	700	700	1,300	0	8,738
- Commodity based derivatives	(2,920)	577	3,318	1,031	(88)	0	1,918
- Exploration expenditure written off	50	1,610	0	0	0	0	1,660
Investments in associated companies	125	2,253	4,516	1,066	461	0	8,421
Other segment non-current assets	153,115	107,261	35,552	27,627	2,933	0	326,488
Non-current assets, not allocated to segments**							18,519
Total non-current assets							353,428
Additions to PP&E and intangible assets***	31,100	36,200	2,100	4,800	800	0	75,000

* Pension cost includes early retirement cost (exclusive of curtailment effects) and past service cost.

** Deferred tax assets, post employment benefit assets and non-current financial instruments are not allocated to segments.

*** Excluding movements due to changes in abandonment and removal obligations.

For the year ending 31 December 2009, the International Exploration and Production segment recognised net impairment losses of NOK 6.3 billion, mainly related to assets in the Gulf of Mexico. The net impairment losses consist of impairment losses of NOK 8.0 billion and reversals of previous periods impairment losses of NOK 1.7 billion. The net impairment losses have been presented as Exploration expenses of NOK 5.4 billion and Depreciation, amortisation and net impairment losses of NOK 0.9 billion on the basis of their nature as intangible assets (exploration assets) and property, plant and equipment (development and producing assets), respectively.

In 2009, Statoil also recognised impairment losses of NOK 5.4 billion related to refinery assets in the Manufacturing and Marketing segment. The basis for the impairment losses are value in use estimates triggered by decreasing expectations on refining margins in NOK. The impairment losses have been presented as Depreciation, amortisation and net impairment losses. In addition, Statoil has recognised an impairment loss of NOK 1.4 billion in 2009 related to an investment in a refinery company which was classified as an available for sale financial asset. This impairment loss was not allocated to a specific segment but was presented as a financial item.

In 2008, Statoil recognised net impairment losses of NOK 4.5 billion in the International Exploration and Production segment, of which the main part relates to assets in the Gulf of Mexico. The impairment charges have been presented as Exploration expenses of NOK 2.4 billion and Depreciation, amortisation and impairment losses of NOK 2.1 billion.

In 2007, the International Exploration and Production segment recognised net impairment losses of NOK 1.2 billion, of which the main part related to exploration and production assets (Intangible assets and Property, plant and equipment) in the Gulf of Mexico while the Manufacturing and Marketing segment recognised an impairment loss of NOK 0.9 billion related to property plant and equipment and intangible assets in the Energy and Retail business in Sweden.

In assessing the need for impairment of the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to the 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, such as tax rates and horizon of cash flows. The discount rate is 6.5% real after tax in a 28% tax regime and is derived from Statoil's weighted average cost of capital.

With effect from 1 January 2008, the internal price for natural gas sold between the segments Exploration and Production Norway and Natural Gas was updated to better reflect changes in the markets for competing energies.

The 2007 Financial statements included an expense of NOK 10.7 billion before tax related to restructuring expenses and other expenses related to the merger between Statoil and Hydro's oil and gas division in 2007. The major part of these expenses was related to pensions and early retirement packages offered to all employees above the age of 58 years. The total expense impacted the net operating income of all segments, and most significantly the segment Exploration and Production Norway. Based on a settlement and estimate changes in 2008, Statoil recognised NOK 1.7 billion before tax as a cost reduction in 2008. The main part of this amount relates to the segment Exploration and Production Norway.

Geographical areas

Statoil is present in 42 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 2009, 2008 and 2007 is presented below:

(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	18,137	361,090
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 from associated companies)	212,167	88,532	34,926	102,367	25,663	463,655

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 december 2008						
Norway	260,171	79,813	44,536	79,659	31,105	495,284
United States	24,712	8,795	1,660	20,182	2,545	57,894
Sweden	0	0	0	23,428	2,618	26,046
Denmark	0	0	0	16,858	2,558	19,416
Singapore	11,203	1,906	0	0	0	13,109
UK	1,982	10,878	2	0	2,800	15,662
Other	7,305	930	198	16,885	2,008	27,326
Total revenues (excluding net income from associated companies)	305,373	102,322	46,396	157,012	43,634	654,737

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2007						
Norway	209,764	62,911	47,119	52,537	14,342	386,673
United States	24,142	5,269	1,766	22,823	(864)	53,136
Sweden	0	0	0	15,217	7,892	23,109
Denmark	0	0	0	13,161	1,759	14,920
Singapore	13,861	0	0	367	0	14,228
Other	13,290	2,485	139	11,517	2,691	30,122
Total revenues (excluding net income from associated companies)	261,057	70,665	49,024	115,622	25,820	522,188

Assets by geographic areas

(in NOK million)	2009	2008	2007
Norway	228,153	220,794	204,401
United States	38,993	50,587	38,672
Brazil	29,549	15,743	2,266
Angola	23,345	23,807	15,906
Canada	20,533	17,151	14,423
Azerbaijan	17,331	21,396	16,279
Algeria	9,265	11,270	8,371
Other areas	37,975	47,769	31,305
Total non-current asset (excluding deferred tax asset, pension and financial non-current items) at 31 December	405,144	408,517	331,623

Major customers

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

6 Financial risk management

General information relevant to 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 with the purpose of avoiding sub-optimisation and utilising correlations observed from a group perspective. Only summing up the different market risks without including the correlations will overestimate our total market risk. Due to this the group utilises correlations between all the most important market risks, such as oil and natural gas prices, product prices, currencies, and interest rates, to calculate the overall market risk and thereby utilise the natural hedges embedded in our portfolio. This approach also reduces the number of unnecessary transactions which reduces transaction costs and avoids sub-optimisation.

In order to achieve the above results, the group has centralised trading mandates such that all major/strategic transactions are co-ordinated through our Corporate Risk Committee. Local mandates are relatively small.

The group's 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 the group's risk policies. The Chief Financial Officer assisted by the Corporate Risk 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 the group from our Corporate Risk Department.

Financial risks

Statoil's activities expose the group to financial risks as defined by IFRS 7:

- Market risk (including commodity price risk, interest rate risk, currency 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 positions, defined as having a time horizon of six months or more, are managed at the corporate level while short-term positions 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 contractual arrangements (derivatives) 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.

Commodity price risk

Commodity price risk represents the group's most important short-term market risk and is monitored every day against established mandates as defined by the group's governing policies. To manage short-term commodity risk, the group enters into commodity-based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and petroleum 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, 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

Statoil's operating results and cash flows are affected by price developments of its main products, oil and gas, in addition to foreign currency fluctuations of the most significant currencies, the NOK, EUR and GBP, against the USD.

Statoil is managed as a USD company for currency management purposes. Foreign exchange risk is managed at corporate level in accordance with policies and mandates.

The group'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 has assets and liabilities with variable interest rate that expose the group to cash flow risk caused by market interest rate fluctuations. The group 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 becomes more diversified than by only being able to use the US floating rate debt market.

Statoil principally manages the group's interest rates by converting 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. The group's interest rate policy also includes a mandate to deviate from base policy and keep part of the long term debt in fixed interest rates.

Equity price risk

The group's captive insurance company holds listed equity securities as a part of its portfolio. In addition, the group holds some other non-listed equity securities for long-term strategic purposes. By holding these assets the group is exposed to equity price risk, defined as the risk of declining equity prices, 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 the group'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.

Liquidity risk

Liquidity risk is the risk that Statoil will not be able to meet obligations associated with financial liabilities when due. The purpose of liquidity and current liability management is to make certain that the group 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. 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. Planned capital expenditures have been adjusted and Statoil has, and will continue, to implement initiatives to cut costs. In order to secure necessary financial flexibility, which includes meeting the group's financial obligations, Statoil maintains what is believed 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 on a monthly basis.

Statoil's operating cash flows are significantly impacted by the volatility in the oil and gas prices; however, during 2009 the group's overall liquidity position remained strong and the policies for managing liquidity remained unchanged.

The main cash outflows are the annual dividend payment and Norwegian Petroleum Tax payments six times per year. If liquid assets one month after tax- and dividend payment dates are below 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 2 billion, supported by 17 core banks. The facility is undrawn and provides secure access to funding, supported by best available (A1/P1) short-term rating. This credit facility matures in December 2011 and is expected to be renewed and increased during 2010.

For non-current funding purposes Statoil raises debt in all main capital markets (USA, Europe and Japan). 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. Our policy is to have a smooth maturity profile with repayments not exceeding 5% of capital employed in any year for the nearest five years. Statoil's long term debt has an average maturity of approximately 10 years.

For more information about the group's non-current financial liabilities see note 22 Non-current financial liabilities.

The table below shows a maturity analysis of the group's financial liabilities and financial assets held to manage liquidity risk based on undiscounted contractual cash flows. 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 2009						
Non-derivative financial liabilities	(72,540)	(17,910)	(24,854)	(49,836)	(52,349)	(217,489)
Derivative financial instruments	(613)	24	(766)	(1,672)	(1,064)	(4,091)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	335	0	0	0	0	335
Current financial investments	7,022	0	0	0	0	7,022
Cash & cash equivalent	24,723	0	0	0	0	24,723
Total asset held	32,080	0	0	0	0	32,080
At 31 December 2008						
Non-derivative financial liabilities	(98,820)	(8,197)	(11,150)	(13,056)	(28,073)	(159,296)
Derivative financial instruments	(13,634)	(120)	(73)	(174)	(421)	(14,422)
Financial assets held for managing liquidity risk						
Current derivative financial instruments	173	0	0	0	0	173
Current financial investments	9,747	0	0	0	0	9,747
Cash & cash equivalent	18,638	0	0	0	0	18,638
Total asset held	28,558	0	0	0	0	28,558

As of 31 December 2009 Statoil's liquid assets amounted to NOK 31.7 billion and total liquidity reserve, defined as the total of the group's liquid assets and unused credit facility, amounted to NOK 43.3 billion .

Credit risk

Credit risk is the risk that the group's customers or counterparties will cause the group financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from financial investments, derivative financial instruments and deposits with financial institutions. Theoretically, the group's maximum credit exposure for financial assets is the aggregated balance sheet carrying amounts of financial investments (excluding equity investments of NOK 6.5 billion in 2009 and NOK 6.5 billion in 2008), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents.

Key elements of our credit risk management approach include:

- A global credit risk policy
- Credit mandates
- An internal credit rating process
- Credit risk mitigation tools
- Continuous monitoring and managing credit exposures

Prior to entering into transactions with new counterparties, the group's credit policy requires all counterparties to be formally identified, approved, and assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed at a minimum annually and monitored continuously. Counterparty risk assessments are based on a quantitative and qualitative analysis of recent financial statements and other relevant business information. In addition, Statoil evaluates any past payment performance, the counterparties' size and business diversification, and the inherent industry risk. The internal credit ratings reflect our assessment of the counterparties' credit risk. Exposure limits are determined 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.

The group uses risk mitigation tools to reduce or control credit risk both on a counterparty and portfolio level. The main tools are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only investment grade international banks are accepted.

The group 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. The group 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 the group'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	Current derivative financial instruments	Non-current derivative financial instruments
At 31 December 2009				
Investment grade, rated A or above	1,081	25,119	3,501	10,975
Other investment grade	1,387	5,417	1,060	6,669
Non-investment grade or not rated	696	22,471	635	0
Total financial asset	3,164	53,007	5,196	17,644
At 31 December 2008				
Investment grade, rated A or above	1,360	33,737	6,243	15,484
Other investment grade	3	8,431	1,296	5,798
Non-investment grade or not rated	1,408	24,476	761	0
Total financial asset	2,771	66,644	8,300	21,282

As of 31 December 2009, NOK 4.7 billion is received in cash as collateral to offset a portion of this group credit exposure. See note 26 Current financial liabilities for more information on collateral held.

7 Capital management

Capital management

Statoil's capital management policy is to maximise value creation over time, while maintaining a strong financial position and a long-term credit rating at least within the single A category.

Management makes regular use of Free 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 from operations after tax with the addition of certain adjustments employed by major rating agencies. These adjustments include cash effects from operating leases, post retirement benefit obligations, capitalised interest, asset retirement obligations and reclassifications of working capital cash flow changes.

ND in this respect is defined as Statoil's current and non-current interest bearing debt adjusted for Statoil's liquidity positions and adjusted for the adjustments defined above. In addition certain adjustments are made through the addition of project financing, balances related to the Marketing instruction, and balances held by the group's captive insurance company.

CE is Statoil's total equity plus net interest bearing debt, including debt adjustments defined above.

Credit rating

Credit rating is important for Statoil to provide necessary financial flexibility to support a dynamic strategy and provide flexibility through economic and market cycles. Statoil have credit ratings from Moody's and Standard & Poor's and our 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. Our current long-term credit ratings are Aa2 and AA- from Moody's and Standard & Poor's respectively. The short-term rating from Moody's is P-1 and A-1+ from Standard & Poor's. We have the intention to keep financial ratios that we consider adequate for maintaining credit ratings at levels consistent with our 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 fully owned subsidiaries to fund capital requirements within the group. With effect from 1 January 2009, Statoil ASA transferred the ownership of its Norwegian Continental Shelf (NCS) net assets to Statoil Petroleum AS. Following the transfer, the majority of corporate assets are owned by Statoil Petroleum AS. Effective from the same date, Statoil Petroleum AS became 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. All financing of subsidiaries, associates and jointly controlled entities is based on arm's-length principles. Project specific financing may also be used with the primary objective to mitigate risk.

Capital distribution
Shareholder return consists of dividend payments, share buy-backs and share price development. Present dividend policy reflects:

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 direct link to the IFRS net income has been removed, and the focus will be on growing the annual cash dividend per share in line with long-term underlying earnings. The new policy does not imply a change in the long-term dividend level, including potential share buy-backs, compared to the previous policy. Statoil emphasises the importance of maintaining an attractive dividend level also in the future.

8 Remuneration

	For the year ended 31 December		
(in NOK million except number of man-labour year)	2009	2008	2007
Salaries**	18,472	18,670	17,243
Pension costs	3,538	2,851	3,131
Payroll tax	3,023	2,676	2,930
Other compensations and social costs	2,177	2,102	1,997
Total payroll costs	27,210	26,299	25 301*
Average man-labour year	28,107	28,001	27,641

*Total payroll cost for 2007 is exclusive of termination benefits.
** Salaries are exclusive of reimbursement from the The Norwegian Labour and Welfare Administration.

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 Pension liabilities.

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 370, NOK 340 and NOK 246 million related to the 2009, 2008 and 2007 programs, respectively. For the 2010 program (granted in 2009) the estimated compensation expense is NOK 427 million. At 31 December 2009 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 816 million.

9 Other expenses

Auditors' remuneration

(in NOK million, excluding VAT)	Audit fee	Audit related fee	Other service fee	Total
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
2008				
Ernst & Young - Norway	35.0	4.9	0.1	40.0
Ernst & Young - outside Norway	25.3	3.8	0.1	29.2
Total	60.3	8.7	0.2	69.2
2007				
Ernst & Young - Norway	20.7	7.3	0.1	28.1
Ernst & Young - outside Norway	24.1	0.8	0.3	25.2
Total	44.8	8.1	0.4	53.3

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 8.9, NOK 8.5 and NOK 6.1 million for 2009, 2008 and 2007, respectively.

The increase in audit fees from 2007 to 2008 are mainly due to the increase in activity in connection with the merger with Hydro Petroleum.

Research and development expenditures

Research and development expenditures were NOK 2,073, NOK 2,243 and NOK 1,969 million in 2009, 2008 and 2007, 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 Statement of income.

10 Financial items

(in NOK million)	2009	For the year ended 31 December 2008	2007
Foreign exchange gains (losses) non-current financial liabilities	0	(11,252)	5,944
Foreign exchange gains (losses) derivative financial instruments	9,722	(25,001)	8,276
Foreign exchange gains (losses) taxes payable	(1,930)	-	-
Other foreign exchange gains (losses)	(5,799)	3,690	(4,177)
Net foreign exchange gains (losses)	1,993	(32,563)	10,043
Dividends received	66	290	523
Gains (losses) financial investments	875	4,796	(723)
Interest income financial investments	354	975	338
Interest income non-current financial receivables	106	130	197
Interest income current financial assets and other financial income	2,307	6,016	1,970
Interest income and other financial items	3,708	12,207	2,305
Capitalised borrowing costs	1,351	1,225	2,680
Accretion expense asset retirement obligation	(2,432)	(2,107)	(2,099)
Interest expense non-current financial liabilities incl. derivatives	(2,386)	(1,850)	(2,447)
Gains (losses) derivative financial instruments	(6,593)	5,632	513
Interest expense current financial liabilities and other finance expenses	(2,391)	(909)	(1,388)
Interest and other finance expenses	(12,451)	1,991	(2,741)
Net financial items	(6,750)	(18,365)	9,607

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 for the year ended 31 December 2009 resulted in fair value gains on these positions which are recognised in the statement of income. Correspondingly, strengthening of USD versus the NOK for the year ended 31 December 2008 resulted in fair value losses and weakening of USD versus NOK for the year ended 31 December 2007 resulted in fair value gains.

For comparison of Other foreign exchange gains and (losses) in 2009 with 2008 and 2007, one need to take into account that the parent company Statoil ASA changed its functional currency from NOK to USD effective from 1 January 2009. For further information see note 1 Organisation.

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. Increasing USD interest rates for the year ended 31 December 2009 resulted in fair value losses on these positions. Correspondingly, decreasing USD interest rates for the year ended 31 December 2008 and the year ended 31 December 2007 resulted in fair value gains.

Included in Interest expense current financial liabilities and other finance expenses is an impairment loss of NOK 1.4 billion related to the Pernis refinery investment for the year ended 31 December 2009.

Capitalised borrowing costs were reduced due to more fields going into production in 2009 and 2008 compared to 2007.

All hedge accounting relationships, which related to a portion of the non-current debt portfolio, were discontinued in the first quarter of 2009. Fair value hedge adjustments of NOK 2.5 billion are amortised over the remaining life of these loans (14 to 19 years). The amortised income recognised in Gains (losses) derivative financial instruments is NOK 198 million for the year ended 31 December 2009.

11 Income taxes

Significant components of income tax expense were as follows

(in NOK million)	2009	2008	2007
Norway offshore	80,944	124,775	93,838
Norway onshore	4,027	3,378	1,924
Other countries upstream [1]	5,149	9,704	9,928
Other countries downstream [1]	770	306	535
Current income tax expense	90,890	138,163	106,225
Norway offshore	9,358	3,567	(555)
Norway onshore	242	(4,992)	373
Other countries upstream [1]	(3,094)	993	(3,688)
Other countries downstream [1]	(221)	(534)	(185)
Deferred tax expense	6,285	(966)	(4,055)
Income tax expense	97,175	137,197	102,170

[1] Includes Norwegian taxes on income in other countries.

Reconciliation of Norwegian nominal statutory tax rate of 28% to effective tax rate

(in NOK million)	2009	2008	2007
Norway offshore	122,074	171,150	124,707
Norway onshore	(10,700)	(6,260)	7,331
Other countries upstream	2,733	14,610	13,727
Other countries downstream	783	967	1,046
Total income before tax	114,890	180,467	146,811
Calculated income taxes at statutory rates:			
Calculated income taxes at statutory rate (Norwegian statutory tax rate 28%)	32,169	50,531	41,107
Petroleum surtax at statutory rate (Norwegian special tax rate 50%)*	61,037	85,575	62,353
Uplift*	(5,052)	(5,047)	(4,365)
Other countries upstream	1,289	6,606	2,397
Other countries downstream	330	(497)	57
Permanent differences caused by USD as functional currency	6,935	0	0
Other items	467	29	621
Income tax expense	97,175	137,197	102,170
Effective tax rate (%)	84.58	76.02	69.59

*Uplift is deducted by 7.5% per year for four years, as from the year of investment. At the end of 2009 and 2008 unrecognised uplift credits amounted to NOK 15.5 and 15.1 billion, respectively.

The higher tax rate for the year ended 31 December 2009 compared to 2008 is mainly caused by significant taxable exchange gains in the NOK based tax return in the parent company. These taxable exchange gains do not impact the Statement of income in the parent company, whose functional currency is USD. The effect amounts to NOK 6.9 billion.

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 2008									
Deferred tax assets	1,356	5,970	3,505	1,864	0	28,195	10,607	5,693	57,190
Deferred tax liabilities	0	(9,063)	0	(91,816)	(18,528)	0	0	(4,625)	(124,032)
Net asset (liability) at 31 December 2008	1,356	(3,093)	3,505	(89,952)	(18,528)	28,195	10,607	1,068	(66,842)
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	(9,014)	0	(96,799)	(20,091)	0	0	(9,636)	(135,540)
Net asset (liability) at 31 December 2009	907	(6,891)	3,098	(86,637)	(20,091)	34,072	8,148	(6,968)	(74,362)

Analysis of movements during the year	2009	2008	2007
Deferred tax liability at 1 January	66,842	66,684	71,276
Charged (credited) to the Consolidated statement of income	6,285	(966)	(4,055)
Other comprehensive income	759	1,166	364
Charged (credited) to Equity	155	(364)	(189)
Translation differences and other	321	322	(712)
Deferred tax liability at 31 December	74,362	66,842	66,684

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

At the end of 2009, Statoil had recognised net deferred tax assets of NOK 1.96 billion, primarily in the International Exploration and Production segment, as it is considered probable that taxable profit will be available to utilise the deferred tax assets.

Unrecognised deferred tax assets

(in NOK million)	At 31 December 2009	2008
Deductible temporary differences	14,519	8,016
Tax losses carry forward	4,461	4,744

The tax losses carry-forwards that have not been recognised, primarily in the US, expire in the period 2019-2025. The unrecognised deductible temporary differences, primarily in Angola, 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 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 2009, 2008 and 2007 respectively, calculated as follows:

	2009	2008	2007
Net income attributable to equity holders of the parent company (in NOK million)	18,313	43,265	44,096
Weighted average number of ordinary shares outstanding (in thousands of shares):			
Issued shares at 1 January	3,189,902	3,188,647	2,166,144
Effect of treasury shares held	(6,029)	(2,693)	(21,681)
Effect of shares issued in the merger with Hydro Petroleum	-	-	1,051,404
Weighted average number of ordinary shares at 31 December	3,183,874	3,185,954	3,195,867
Earnings per share for income attributable to equity holders of the company - basic and diluted (NOK)	5.75	13.58	13.80

The group has no share programs with significant dilutive effects and the calculated diluted earnings per share rounds to be the same amount as the calculated basic earnings per share.

For the purposes of calculating earnings per share in connection with the merger with Hydro Petroleum, weighted average number of ordinary shares outstanding was set as the total of former Statoil's weighted average number of ordinary shares outstanding and Hydro's weighted average number of outstanding shares multiplied by the number of Statoil's ordinary shares which Hydro shareholders received for each Hydro share in connection with the merger.

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 2007	14,041	521,542	41,162	14,742	4,647	49,110	645,244
Acquisitions through business combinations	160	0	0	0	0	14,068	14,228
Additions and transfers	3,139	47,327	3,234	1,103	819	9,627	65,249
Disposals assets at cost	(1,265)	(7,907)	(4,622)	(546)	(33)	(1,089)	(15,462)
Effect of movements in foreign exchange - assets	2,149	21,104	1,710	1,229	171	6,167	32,530
Cost at 31 December 2008	18,224	582,066	41,484	16,528	5,604	77,883	741,789
Accumulated depr. and impairment losses at 31 December 2007	(9,745)	(323,491)	(25,761)	(5,487)	(430)	(1,978)	(366,892)
Depreciation and amortisation	(1,005)	(36,872)	(1,607)	(672)	(396)	0	(40,552)
Transfers	0	(2,343)	0	0	0	2,343	0
Net impairment losses	0	(735)	0	0	0	(1,409)	(2,144)
Accumulated depreciation and impairment disposed assets	1,138	6,667	1,446	336	0	117	9,704
Effect of movements in foreign exchange – depreciation and impairment losses	(1,241)	(8,801)	(897)	(488)	(43)	(594)	(12,064)
Accumulated depr. and impairment losses at 31 December 2008	(10,853)	(365,575)	(26,819)	(6,311)	(869)	(1,521)	(411,948)
Carrying amount at 31 December 2008	7,371	216,491	14,665	10,217	4,735	76,362	329,841
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 2008	18,224	582,066	41,484	16,528	5,604	77,883	741,789
Additions and transfers	4,379	58,269	2,528	1,431	(788)	20,068	85,887
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	18,542	618,487	43,354	15,735	4,079	89,221	789,418
Accumulated depr. and impairment losses at 31 December 2008	(10,853)	(365,575)	(26,819)	(6,311)	(869)	(1,521)	(411,948)
Depreciation and amortisation	(1,305)	(42,347)	(1,994)	(617)	(333)	0	(46,596)
Net impairment losses	(2,162)	(1,223)	(3,248)	0	0	319	(6,314)
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	219	711	184	1,135	14,542
Accumulated depr. and impairment losses at 31 December 2009	(12,201)	(397,591)	(31,703)	(6,003)	(1,018)	(67)	(448,583)
Carrying amount at 31 December 2009	6,341	220,896	11,651	9,732	3,061	89,154	340,835
Estimated useful lives (years)	3 - 10	*	15 - 20	20 - 33	20 - 25		

In 2009 and 2008, capitalised borrowing cost amounted to NOK 1.4 and NOK 1.2 billion, respectively. In addition to depreciation, amortisation and impairment losses specified above, certain intangible assets, see note 14 Intangible assets, have been amortised by NOK 1.2 and NOK 0.3 billion in 2009 and 2008, respectively.

Transfer of assets to Property, plant and equipment from Intangible assets in 2009 and 2008 amounted to NOK 4.9 and NOK 1.5 billion, respectively.

*Depreciation according to Unit of production method, see note 2 Significant accounting policies.

See note 5 Segments for description of asset impairments.

14 Intangible assets

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2007	40,511	6,598	47,109
Acquisitions through business combinations	1,748	0	1,748
Other additions	17,472	176	17,648
Disposals intangible assets at cost	(160)	(1,696)	(1,856)
Transfers of intangible assets	(1,464)	12	(1,452)
Expensed exploration expenditures previously capitalised	(3,706)	0	(3,706)
Effect of movements in foreign exchange	7,087	441	7,528
Cost at 31 December 2008	61,488	5,531	67,019
Accumulated amortisation and impairment losses at 31 December 2007		(2,259)	(2,259)
Depreciation, impairments and amortisation for the year		(300)	(300)
Disposals amortisation and impairment losses		1,686	1,686
Effect of movements in foreign exchange - amortisation and imp. losses		(110)	(110)
Accumulated amortisation and impairment losses at 31 December 2008		(983)	(983)
Carrying amount at 31 December 2008	61,488	4,548	66,036

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2008	61,488	5,531	67,019
Other additions	7,816	1,614	9,430
Disposals intangible assets at cost	(774)	(49)	(823)
Transfers of intangible assets	(4,888)	10	(4,878)
Expensed exploration expenditures previously capitalised	(6,998)	0	(6,998)
Effect of movements in foreign exchange	(7,284)	(457)	(7,741)
Cost at 31 December 2009	49,360	6,649	56,009
Accumulated amortisation and impairment losses at 31 December 2008		(983)	(983)
Depreciation, impairments and amortisation for the year		(1,161)	(1,161)
Disposals amortisation and impairment losses		15	15
Effect of movements in foreign exchange - amortisation and imp. losses		373	373
Accumulated amortisation and impairment losses at 31 December 2009		(1,756)	(1,756)
Carrying amount at 31 December 2009	49,360	4,893	54,253

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.

Included in Other intangible assets is goodwill of NOK 4.0 billion as of 31 December 2009 (NOK 3.0 billion as of 31 December 2008 and as of 31 December 2007).

See note 5 Segments for description of asset impairments.

For 2008, additions in Intangible assets of NOK 19.4 billion include acquisition of business from Anadarko Petroleum Corporation and assets acquired from Chesapeake Energy Corporation in addition to other exploration activity capitalised during 2008. See note 3 Business combinations and note 4 Asset acquisitions and disposals for details on the acquisitions during 2008.

15 Investments in associated companies

(in NOK million)	2009	2008
Carrying amount associated companies at 31 December	10,056	12,640
Net income from associated companies	1,778	1,283

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 PHC Ltd (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 using the equity method.

16 Non-current financial assets

	At 31 December	
(in NOK million)	2009	2008
Bonds	6,726	9,984
Listed equity securities	4,318	2,276
Non-listed equity securities	2,223	4,205
Financial investments	13,267	16,465

Of the Financial investments at 31 December 2009, NOK 11.1 billion relate to investment portfolios held by the group's captive insurance company and is accounted for using the fair value option. Correspondingly NOK 12.3 billion were related to the group's captive insurance portfolios at 31 December 2008.

All non-listed equity securities in the above table 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 Statement of income. The total change of NOK 2.0 billion in 2009 is mainly caused by an impairment loss of NOK 1.4 billion related to the Pernis refinery investment.

During 2009 NOK 0.07 billion has been transferred out of Other comprehensive income. For 2008 a loss of NOK 1.4 billion was recognised in Other comprehensive income.

	At 31 December	
(in NOK million)	2009	2008
Financial receivables interest bearing	3,164	2,771
Non-financial receivables	2,583	2,143
Financial receivables	5,747	4,914

Included in Financial receivables interest bearing are project financing related to the associated company BTC, Petrocedeño (former Sincor) and Naturkraft.

Included in Non-financial receivables are long term prepayments.

Of the Financial receivables NOK 3.2 billion is classified in the loan and receivables category, the remaining is classified as non-financial assets. Financial receivables' carrying amounts reasonably 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.

	At 31 December	
(in NOK million)	2009	2008
Crude oil	11,371	7,249
Petroleum products	7,778	6,338
Other	1,047	1,564
Inventories	20,196	15,151

A write-down of inventory to net realisable value has been recognised as an expense in the period. The write-down was insignificant at year end 2009 and amounted to NOK 3.9 billion at year end 2008.

18 Trade and other receivables

	At 31 December	
(in NOK million)	2009	2008
Financial trade and other receivables:		
Trade receivables	48,827	57,796
Receivables joint ventures	3,579	7,131
Receivables associated companies and other related parties	601	1,717
Total financial trade and other receivables	53,007	66,644
Non-financial trade and other receivables	5,888	3,287
Trade and other receivables	58,895	69,931

For more information about the credit quality of Statoils financial assets see note 6 Financial risk management. For currency sensitivities see note 31 Financial instruments: measurement and market risk sensitivities.

19 Current financial investments

	At 31 December	
(in NOK million)	2009	2008
Commercial papers	5,356	7,131
Money market funds	1,584	2,602
Other	82	14
Financial investments	7,022	9,747

Current financial investments at 31 December 2009 are classified as held for trading, except for NOK 5.0 billion related to investment portfolios held by the group's captive insurance company which are accounted for using the fair value option. The corresponding balance at 31 December 2008 was NOK 1.9 billion accounted for using the fair value option.

Current financial investments at 31 December 2009 and 2008 are measured at fair value with gains and losses recognised in the statement of income.

20 Cash and cash equivalents

	At 31 December	
(in NOK million)	2009	2008
Cash at bank	9,872	12,165
Time deposits and collateral deposits	14,851	6,473
Cash and cash equivalents	24,723	18,638

Cash and cash equivalents at 31 December 2009 include restricted cash of NOK 1.8 billion related to trading activities, correspondingly restricted cash at 31 December 2008 was NOK 4.1 billion. This restricted cash is related to certain collateral requirements set out by exchanges where the group is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

The overdraft bank balances and overdraft facilities are included in note 26 Current financial liabilities. For reconciliation of Cash and cash equivalents reported in the Consolidated balance sheet, see Consolidated statement of cash flows.

21 Transactions impacting shareholders equity

For information regarding changes in equity related to the merger with Hydro Petroleum, see information in note 32 Merger with Hydro Petroleum.

The annual general meeting in 2006 authorised the board of directors to acquire treasury shares for subsequent annulment. Under an agreement with the Norwegian State a proportion of the State's shares should later be redeemed and annulled, so that the State's ownership interest remained unchanged. Both the acquired shares and the firm obligation have been included in Treasury shares since the date the treasury shares have been acquired in the market according to the authorisation. The extraordinary general meeting on 5 July 2007 approved a reduction of the share capital by NOK 50,397,120 through the annulment of 5,867,000 acquired treasury shares, and redemption and annulment of an additional 14,291,848 shares held by the State. The State, represented by the Ministry of Petroleum and Energy, received a payment of NOK 2,441,899,894 for the shares. The amount corresponded to the average volume-weighted price of the company's treasury shares acquired in the market with the addition of interest. As of 31 December 2009 the Norwegian State had an ownership interest in Statoil of 67% (excluding Folketrygdfondet (Norwegian national insurance fund) of 3.26%). The Norwegian State is defined as a related party, see note 29 Related parties.

After the annulment in 2007, Statoil share capital of NOK 7,971,617,757.50 comprised 3,188,647,103 shares at a nominal value of NOK 2.50.

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 15 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.

During 2009 a total of 2,663,357 treasury shares were purchased for NOK 343 million. At 31 December 2009 Statoil had 6,028,607 treasury shares all of which are related to the group's share saving plan.

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 7.25 in 2009 for Statoil ASA and NOK 8.50 and NOK 9.12 in 2008 and 2007, respectively for the former Statoil ASA. In addition, under terms of the merger plan Hydro Petroleum was charged the dividend payment of NOK 6.1 billion paid by Norsk Hydro ASA to its shareholders in 2007. Dividend payments for 2007 included in Statoil's equity include both the former Statoil ASA and Hydro Petroleum dividend payments. A dividend for 2009 of NOK 6.00 per share, amounting to a total dividend of NOK 19.1 billion, will be proposed at the annual general meeting in May 2010. The proposed dividend is not recognised as a liability in the financial statements.

Retained earnings available for distribution of dividends at 31 December 2009 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 117,160 million (before provisions for proposed dividend for the year ended 31 December 2009 of NOK 19,100 million). This differs from retained earnings in the Consolidated financial statements of NOK 145,909 million. In accordance with legal requirements dividends is not allowed to reduce the shareholders' equity of the parent company below 10% of total assets.

22 Non-current financial liabilities

	Weighted average interest rates in %		Carrying amount in NOK million at 31 December		Fair value in NOK million at 31 December	
	2009	2008	2009	2008	2009	2008
Financial liabilities measured at amortised cost						
Unsecured bonds						
US dollar (USD)	5.85	6.84	40,610	23,617	43,632	25,312
Euro (EUR)	5.13	5.58	27,515	6,101	30,397	6,458
Swiss franc (CHF)		4.01	-	1,023	-	1,032
Japanese yen (JPY)	1.66	1.65	312	388	322	376
Great Britain Pound (GBP)	6.71	6.13	9,556	2,271	11,391	1,935
Total			77,993	33,400	85,742	35,113
Unsecured loans						
US dollar (USD)	0.71	2.74	5,697	6,899	5,639	6,726
Japanese yen (JPY)	1.65	1.65	501	620	516	607
Secured bank loans						
US dollar (USD)	3.74	5.86	864	1,252	894	1,262
Other currencies	4.63	6.82	135	63	135	63
Financial lease liabilities			13,747	5,665	13,747	5,665
Other liabilities			293	864	293	855
Total			21,237	15,363	21,224	15,178
Financial liabilities measured at amortised cost subject for hedge accounting						
US dollar (USD)		5.94	-	9,957	-	7,403
Euro (EUR)		5.13	-	2,097	-	2,050
Total			-	12,054	-	9,453
Grand total liabilities outstanding			99,230	60,817	106,966	59,744
Less current portion			3,268	6,211	3,268	6,183
Financial liabilities			95,962	54,606	103,698	53,561

On 11 March 2009 Statoil ASA executed the issuance of a GBP 0.8 billion bond maturing in March 2031, a EUR 1.2 billion bond maturing in March 2021 and a EUR 1.3 billion bond maturing in March 2015. All bonds were issued under Statoil ASA's Euro Medium Term Note Programme and have been listed on the London Stock Exchange.

On 23 April 2009 Statoil ASA executed the issuance of a USD 0.5 billion bond maturing in April 2014 and a USD 1.5 billion bond maturing in April 2019. These registered bonds were issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the SEC in the United States.

On 15 October 2009 Statoil ASA executed the issuance of a USD 0.9 billion bond maturing in October 2014. The registered bond was issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the SEC in the United States.

Non-current financial liabilities include financial lease obligations. More information is given in note 27 Leases.

The third section of the table above contains bonds valued at amortised cost as adjusted for the fair value of hedged interest rate risk for the bonds that qualify for hedge accounting. As of 1 January 2009 no bonds are subject to hedge accounting. The table does not illustrate the economic 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 reflect swap agreements.

Fair value is calculated by discounting cash flows based on year-end market interest rates from external sources. Year-end market interest rates used as discount rates are derived from LIBOR and EURIBOR adjusted for credit premiums. Credit premiums are based on indicative pricing from external financial institutions.

				Carrying amount in NOK million at 31 December	
Bond agreement	Fixed interest rate	Issued (year)	Maturity (year)	2009	2008
USD 1500 million	5.250%	2009	2019	8,613	-
USD 900 million	2.900%	2009	2014	5,174	-
USD 500 million	3.875%	2009	2014	2,870	-
USD 500 million	5.125%	2004	2014	2,887	3,498
USD 500 million	6.500%	1998	2028	2,859	3,462
USD 481 million	7.250%	2000	2027	2,776	3,363
USD 300 million	7.750%	1993	2023	1,733	2,100
EUR 1300 million	4.375%	2009	2015	10,782	-
EUR 1200 million	5.625%	2009	2021	9,887	-
EUR 500 million	5.125%	1999	2011	4,148	4,915
EUR 300 million	6.250%	1999	2010	2,494	2,960
GBP 800 million	6.875%	2009	2031	7,421	-
GBP 225 million	6.125%	1998	2028	2,096	2,277

Currency swaps are used for risk management purposes. Unsecured bonds are either denominated in US dollar, amounting to NOK 41.1 billion or the bonds are swapped into US dollar, amounting to NOK 37.9 billion. Interest rate swaps are used to manage the interest rate risk on the unsecured bond contracts with fixed interest rates. As a resul 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.

The group's secured bank loans in USD have been secured by mortgage of shares in a subsidiary and investments in associated companies with a combined book value of NOK 2.3 billion, and the group's pro-rata share of income from certain applicable projects.

The group has 27 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 agreements carrying value are NOK 75.9 billion at the 31 December 2009 closing rate.

The group has a revolving credit facility supported by core banks. For more information see note 6 Financial risk management.

Non-current financial liabilities maturity profile

(in NOK million)	At 31 December 2009	2008
Year 2 and 3	11,757	9,653
Year 4 and 5	11,496	9,739
After 5 years	72,709	35,214
Total repayment of non-current financial liabilities	95,962	54,606

Redemption profile for undiscounted cash flows is shown in note 6 Financial risk management.

Non-current financial liabilities

(in NOK million)	At 31 December 2009	2008
Non-current financial liabilities (in NOK million)	95,962	54,606
Weighted average maturity (years)	9	9
Weighted average annual interest rate (%)	4.77	5.64

23 Pension liabilities

The Norwegian companies in the group are obligated to follow the Act on Mandatory company pensions. The pension scheme follows the requirement as included in the Act.

Statoil ASA and many of its subsidiaries have defined benefit retirement plans, which cover substantially all of their employees. Plan benefits are generally based on years of service and final salary level. 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 companies in Statoil have defined contribution plans. The period's contributions are recognised in the Statement of income as pension cost for the period.

In Norway, Statoil is - due to National agreements - a member of the "agreement-based early retirement plan" (AFP). The members pay an annual fee per active employee. This part of the plan is defined as a multi-employer plan. The administrator of this plan is not able to calculate the members' share of assets and liabilities and this plan is consequently accounted for as a defined contribution plan. In addition the members have an obligation to pay a percentage of the benefits when an employee retires through AFP. This obligation is accounted for as a defined benefit plan. When an employee retires through AFP, Statoil also offers a gratuity. This is also a defined benefit plan, and included in the provision related to the defined benefit plans.

A new legislation on the AFP was passed by the Norwegian Parliament 19 February 2010. This law is one part of the Norwegian pension and insurance reform effective from 1 January 2011. Several new laws affecting Norwegian pension and insurance schemes will be passed during 2010. Together with the revised national state pension and insurance legislation this forthcoming legislation will establish a new framework for private sector pension schemes in Norway which requires review and adaptations of existing schemes. Statoil will undertake a review of the total pension scheme during 2010 as a basis for deciding a revised model based on the new legislation.

The obligations related to the defined benefit plans were measured at 31 December, 2009 and 2008. 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 have been tested against historical observations. At 31 December 2009 the discount rate for the defined benefit plans in Norway was estimated to be 4.75% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 20 year yield curve to match 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, outside the Statement of income. 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 unfunded 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 periodic pension cost

(in NOK million)	2009	2008	2007
Current service cost	2.747	2.361	2,611
Interest cost on prior years' benefit obligation	2,550	2,456	1,713
Expected return on plan assets	(1,896)	(2,101)	(1,829)
Amortisation of actuarial gain or loss related to termination benefits	(172)	(215)	0
Amortisation of past service cost	0	17	2,075
Losses (gains) from curtailment or settlement	0	(7)	(1,641)
Defined benefit plans	3.229	2,511	2,929
Defined contribution plans	240	268	160
Multi-employer plans	69	72	42
Termination benefits	0	0	8,633
Total net pension cost	3,538	2,851	11,764

Pension cost includes social security tax.

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

For information regarding pension benefits for key management personnel, see note 29 Related parties.

In 2007, Statoil ASA offered early retirement (termination benefits) to employees above the age of 58 years (contingent upon certain conditions). The expenses related to termination benefits of NOK 5.6 billion and NOK 3.0 billion were recognised as Operating expenses and Selling, general and administrative expenses, respectively.

Change in projected benefit obligation (PBO)

(in NOK million)	2009	2008
Projected benefit obligation at 1 January	59,206	52,791
Current service cost	2,747	2,361
Interest cost on prior years' benefit obligation	2,550	2,456
Actuarial loss (gain)	(1,308)	3,581
Past service cost	0	18
Benefits paid	(1,520)	(1,302)
Acquisition and sale	0	(670)
Foreign currency translation	(248)	(29)
Projected benefit obligation at 31 December	61,427	59,206

Change in pension plan assets

(in NOK million)	2009	2008
Fair value of plan assets at 1 January	33,698	35,158
Expected return on plan assets	1,896	2,101
Actuarial gain (loss)	2,819	(4,149)
Company contributions (including social security tax)	4,956	1,377
Benefits paid	(385)	(346)
Acquisition and sale	0	(443)
Foreign currency translation	(5)	0
Fair value of plan assets at 31 December	42,979	33,698

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 table Actuarial gains and losses recognised directly in Other comprehensive income below.

Total provision for pensions

(in NOK million)	2009	2008
Balance sheet provision at 1 January	(25,508)	(17,633)
Net periodic pension costs defined benefit plans	(3,229)	(2,511)
Net actuarial (loss) gain recognised in Other comprehensive income	3,191	(7,945)
Less employer contributions/benefit paid during year	4,956	1,377
Less benefit paid during year	1,135	956
Acquisition and sale	0	227
Foreign currency translation and other changes	1,007	21
Balance sheet provision at 31 December	(18,448)	(25,508)

Surplus (deficit) at 31 December

(in NOK million)	2009	2008	2007
Surplus (deficit) at 31 December	(18,448)	(25,508)	(17,633)
Represented by:			
Asset recognised as non-current pension asset	2,694	30	1,622
Liability recognised as non-current pension liability	(21,142)	(25,538)	(19,092)
Liability recognised as current liability	0	0	(163)

Projected benefit obligation splitted on funded and unfunded plans

(in NOK million)	2009	2008	2007
Funded pension plans	(40,212)	(37,446)	(33,278)
Unfunded pension plans	(21,215)	(21,760)	(19,513)
PBO at 31 December	(61,427)	(59,206)	(52,791)

Actuarial gains and losses recognised directly in Other comprehensive income

(in NOK million)	2009	2008	2007
Unrecognised actuarial losses (gains) at 1 January	0	0	0
Actuarial losses (gains) on plan assets occurred during the year	(2,819)	4,149	(272)
Actuarial losses (gains) on benefit obligation occurred during the year	(1,308)	3,581	198
Actuarial losses (gains) related to currency effects on net obligation	3,867	0	0
Foreign exchange translation	(3,103)	0	0
Recognised in the income statement during the year	172	215	0
Recognised in Other comprehensive income during the year	3,191	(7945)	74
Unrecognised actuarial losses (gains) at 31 December	0	0	0

Statoil ASA changed its functional currency as of 1 January 2009, for further information see note 1 Organisation and note 2 Significant accounting policies. In the table above Actuarial losses (gains) related to currency effects on net obligation refer to translation of the net pension obligation in ASA in NOK to the functional currency US dollar. The line Foreign exchange translation refer to translation from functional currency US dollar to presentation currency NOK.

Actual return on plan assets

(in NOK million)	2009	2008	2007
Actual return on plan assets	4.715	(2,048)	1,593

History of experience gains and losses

(in NOK million)	2009
Difference between the expected and actual return on plan assets	
a) Amount	(2,819)
b) Percentage of plan assets	(6.56%)
Experience (gain) loss on plan liabilities	
a) Amount	(1,996)
b) Percentage of present value of plan liabilities	(3.40%)

The cumulative amount of actuarial gains and losses recognised directly in Other comprehensive income amounted to NOK 10.9, NOK 13.3 and NOK 4.2 billion net of tax (negative effect on Other comprehensive income) in 2009, 2008 and 2007, respectively.

Weighted-average assumptions for the year ended (Profit and Loss items) in %	2009	2008
Discount rate	4.50	5.00
Expected return on plan assets	5.75	6.25
Rate of compensation increase	4.00	4.50
Expected rate of pension increase	2.75	3.25
Expected increase of social security base amount (G-amount)	3.75	4.25
Inflation	2.00	2.25

Weighted-average assumptions at end of year (Balance sheet items) in %	2009	2008
Discount rate	4.75	4.50
Expected return on plan assets	6.00	5.75
Rate of compensation increase	4.25	4.00
Expected rate of pension increase	3.00	2.75
Expected increase of social security base amount (G-amount)	4.00	3.75
Inflation	2.25	2.00
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 2009 was 2.0%, 2.0%, 1.5%, 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. Expected attrition at 31 December 2008 was 2.0%, 2.0%, 1.5%, 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.

Expected utilisation of AFP is 50% for employees at 62 years and 30% for the remaining employees at 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), hence reducing the mortality rate with a minimum of 15% for male and 10% for female for each employee is used as the best mortality estimate. The disability table, KU, developed by the insurance company Storebrand, aligns with the actual disability risk for Statoil in Norway.

Below is shown a selection related to demographic assumptions used at 31 December 2009. The table shows the probability of disability or death, 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 shows 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 2009. Actual results may materially deviate from these estimates.

(in NOK billion)	Discount rate 0,25%	-0,25%	Rate of compensation increase 0,25%	-0,25%	Social security base amount 0,25%	-0,25%	Expected rate of pension increase 0,25%	-0,25%
Changes in:								
Projected benefit obligation								
at 31 December 2009	(2.07)	2.21	0.91	(0.92)	(1.86)	2.06	1.00	(0.95)
Service cost 2010	(0.14)	0.15	0.06	(0.06)	(0.13)	0,15	0.06	(0.06)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2009 and 2008. 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 included markup for estimating a longer interest rate than ten year) is applied as a starting point for calculation of return on plan assets. The return in the money market is calculated by taking a deduction on bond yield. Based on historical data, equities and real estate are expected to give a long-term additional return above money market.

In its asset management, the pension fund 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. The pension fund'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. Assets are diversified both in terms of location and different asset classes. Derivatives are used within set limits to facilitate effective asset management.

Pension assets allocated on respective investments classes

(in %)	2009	2008
Equity securities	39.60	19.10
Bonds	39.40	70.20
Commercial papers	14.70	3.30
Real estate	5.10	6.90
Other assets	1.20	0.50
Total	100.00	100.00

Properties owned by Statoil Pension fund amounted to NOK 2.1 billion and NOK 2.2 billion of total pension assets at 31 December 2009 and 2008, respectively, and are rented to Statoil companies.

Statoil's pension fund invests in both financial assets and real estate. The expected rate of return on real estate is expected to be between the rate of return on equity securities and debt securities. The table below presents the portfolio weight and expected rate of return of the finance portfolio as approved by the Board of the Statoil pension fund for 2010. 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	59.50	(+/- 5)	X
Commercial papers	0.50	(+15/- 0.5)	X - 0.4
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.

Contributions to pension plans may either be paid in cash or be deducted from the pension premium fund. The pension premium fund amounted to NOK 7.2 billion and NOK 4.5 billion at 31 December 2009 and 2008, respectively. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. In 2009 a pension premium amounting to NOK 4.1 billion was paid. In addition Statoil intends to pay to the pension premium fund approximately NOK 3.3 billion late March 2010. In 2008, NOK 2.9 billion was deducted from the pension premium fund. The company contribution in 2008, paid in cash, was NOK 0.2 billion (exclusive social security tax). In addition, NOK 1.2 billion was paid to Statoil pension fund as a capital increase in 2008.

The expected company contribution related to 2010 amounts to NOK 2.1 billion.

24 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	
Asset retirement obligations at 1 January 2008	39,581
Liabilities incurred/revision in estimates	5,470
Amounts used and charged against provisions	(675)
Unused amounts reversed	0
Effects of change in the discount rate	(2,234)
Reduction due to disposals	(1,402)
Accretion	2,107
Currency exchange difference	1,239
Asset retirement obligations at 31 December 2008	44,086
Current portion of asset retirement obligations	905
Analysis of provisions and other liabilities at 31 December 2008	
Non current portion of asset retirement obligations	43,181
Other provisions	11,178
Asset retirement obligations, other provisions and other liabilities at 31 December 2008	54,359

(in NOK million)	Asset retirement obligations	Other provisions	Other liabilities	Total Provisions
Non-current portion at 1 January 2009	43,181	9,660	1,518	54,359
Current portion at 1 January 2009	1,260	500	0	1,760
Provisions at 1 January 2009	44,441	10,160	1,518	56,119
Liabilities incurred/revision in estimates	1,853	(2,002)	15	(134)
Amounts used and charged against provisions	(523)	(608)	0	(1,131)
Unused amounts reversed	0	(153)	0	(153)
Effects of change in the discount rate	3,090	0	0	3,090
Reduction due to disposals	(767)	0	0	(767)
Accretion	2,432	0	0	2,432
Currency exchange difference	(1,599)	(171)	0	(1,770)
Provisions at 31 December 2009	48,927	7,226	1,533	57,686
Current portion at 31 December 2009	515	1,044	0	1,559
Long term interest bearing provisions reported as financial liability	0	293	0	293
Non-current portion at 31 December 2009	48,412	5,889	1,533	55,834

Asset retirement obligations
A majority of expenditures related to asset retirement obligations are currently expected to be paid in the period between 2015 and 2025. Only a minor portion of expenditures are expected to be paid in the next five years. The timing depends primarily on when the production ceases at the various facilities. For further discussion of methods applied and estimates required, see note 2 Significant accounting policies.

Obligations related to environmental remediation and cleanup related to oil and gas producing assets are included in the estimated asset retirement obligations.

25 Trade and other payables

(in NOK million)	At 31 December 2009	2008
Financial trade and other payables:		
Trade payables	17,362	15,582
Non-trade payables and accrued expenses	31,542	35,945
Payables to associated companies and other related parties	9,144	7,463
Total financial trade and other payables	58,048	58,990
Non-financial trade and other payables	1,753	2,210
Trade and other payables	59,801	61,200

Non-trade payables and accrued expenses include provisions for certain claims and litigations that are further described in note 28 Other commitments and contingencies.

For currency sensitivities see note 31 Financial instruments: measurement and market risk sensitivities.

26 Current financial liabilities

(in NOK million)	At 31 December 2009	2008
Bank loans and overdraft facilities	196	906
Collateral liabilities	4,654	10,123
Commercial paper liabilities	0	2,989
Current portion of non-current loans	2,686	5,604
Current portion of financial lease obligations	582	607
Other financial liabilities	32	466
Financial liabilities	8,150	20,695
Weighted interest rate (%)	2.24	2.50

Carrying amount for Current financial liabilities, at amortised cost and accrued interest reasonably approximate fair value.

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

Commercial paper liabilities relate to the US Commercial Paper (CP) program available for short term funding. For more information see note 6 Financial risk management.

At 31 December 2009 and 2008 the group had no committed short-term credit facilities available or drawn.

27 Leases

Statoil leases certain assets, notably vessels and drilling rigs.

Statoil has entered into certain operational lease contracts for a number of drilling rigs as of 31 December 2009. The remaining significant contracts' terms range from three months to four 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 parts of the lease term for the most part 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.

As a member of the Snøhvit sellers' group Statoil has entered into leasing arrangements for 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 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 2009, net rental expense was NOK 10.9 billion (NOK 10.2 billion in 2008 and NOK 5.7 billion in 2007) of which minimum lease payments were NOK 12.7 billion (NOK 11.8 billion in 2008 and NOK 7.1 billion in 2007) and sublease payments received were NOK 1.8 billion (NOK 1.7 billion in 2008 and NOK 1.5 billion in 2007). No material contingent rents have been expensed in 2009, 2008 or 2007.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2009.

Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year-end 2009.

			Financial lease		
(in NOK million)	Operating leases	Operating sublease	Minimum lease payments	Interest	Net present value minimum lease payments
2010	14,017	(1,560)	627	(93)	534
2011	10,929	(736)	638	(106)	532
2012	7,990	(585)	636	(105)	531
2013	5,262	(589)	444	(107)	337
2014	1,860	(146)	431	(116)	315
Thereafter	3,097	(1,324)	3,992	(1,477)	2,515
Total future minimum lease payments	43,155	(4,940)	6,768	(2,004)	4,764

In addition to the Net present value of minimum lease payments set out above (NOK 4,764 million), total finance lease obligations include an amount of NOK 8,983 million relating to leased assets under development. When calculating the obligations for leased assets under development, the net present value presented reflects the assets' estimated percentage of completion, unless another value better reflects the realities of the obligation.

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2009 and 2008:

(in NOK million)	2009	2008
Leased assets under development	8,983	0
Vessels and equipment	4,876	6,501
Accumulated depreciation	(1,404)	(1,205)
Capitalised amount	12,455	5,296

28 Other commitments and contingencies

Contractual commitments

(in NOK million)	2010	2011	Thereafter	Total
Joint Venture related:				
Construction in progress	12,136	8,643	6,756	27,535
Property, plant and equipment and other investments	1,946	68	3	2,017
Acquisition of intangible assets	253	9	0	262
Subtotal Joint Venture related commitments	14,335	8,720	6,759	29,814
Non Joint Venture related:				
Construction in progress	734	0	0	734
Total	15,069	8,720	6,759	30,548

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, 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. As regards assets (e.g. pipelines) that the group accounts for by including 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 (gross commitment less Statoil's ownership share).

Nominal minimum commitments at 31 December 2009:

(in NOK million)	Transport and terminal commitments	Refinery related commitments	Total
2010	8,676	715	9,391
2011	8,266	740	9,006
2012	7,121	938	8,059
2013	6,898	955	7,853
2014	5,881	971	6,852
Thereafter	37,558	21,670	59,228
Total	74,400	25,989	100,389

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 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.

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 2009 the commitment includes an annual capacity of approximately 10.1 bcm for a remaining period of 19 years. Such commitments have been included in full in the table above, but have been made in part 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 will cover substantially all the cost of unused capacity, if any, while the cost of used capacity will be split in proportion to the produced natural gas volumes of Statoil and the SDFI, respectively.

The Mongstad refinery has entered into 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.

Statoil has entered into a number of general or field specific long-term frame agreements mainly related to crude oil loading and transport capacity availability. The main contracts run up until the end of the respective field lives. Such contracts have not been included in the above table of contractual commitments unless they entail specific minimum payment obligations.

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 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 1.7 billion. A provision of NOK 0.3 billion has been recognised at year end 2009 related to this guarantee.

Statoil has guaranteed for 50%, corresponding to its ownership percentage, of the contractual commitments entered into by Scira Offshore Energy Ltd. (Scira) in connection with the development of the Sheringham Shoal Offshore Wind Farm in the UK. Scira is included in the group financial statements using the equity method. At year end 2009 the maximum exposure under Statoil's guarantee has been estimated to NOK 3.0 billion. The carrying amount of the guarantee 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 is jointly liable for is approximately NOK 3.8 billion with terms extending until 2050. 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 financial statements at year end 2009.

Insurance

The group has taken out insurance to cover certain potential liabilities arising from its operations world wide. This includes liabilities for claims arising from pollution damage. Most of the group's production installations are covered through Statoil Forsikring a.s, which reinsures parts of the risk in the international insurance market. As all significant activities of Statoil Forsikring a.s. relate to insurance for entities and operations consolidated in the group financial statements, IFRS 4 has not been applied to such activities in the group financial statements.

Statoil Forsikring a.s is member of two mutual insurance companies, Oil Insurance Ltd and sEnergy Insurance Ltd. sEnergy ceased operations on 15 May 2006 and the company is in the wind-up phase. Membership in these companies means that Statoil Forsikring is liable for its proportionate share of any losses which might arise in connection with the business operations of the companies. Members of the companies have joint and several liability for any losses that arise within the insurance pool.

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 2009, Statoil was committed to participate in 16 wells in Norway and 37 wells outside Norway, with an average ownership interest of approximately 40%. Statoil's share of estimated expenditures to drill these wells amounts to approximately NOK 9 billion. Additional wells that Statoil may become committed to participate in depending on future discoveries in certain licenses are not included in these numbers.

Statoil ASA issued a declaration to the Norwegian Ministry of Petroleum and Energy (MPE) in 1999 in connection with a dispute between four Åsgard partners and Statoil related to the construction of new facilities for the Åsgard development at the Kårstø Terminal. The declaration confirmed that the MPE will receive similar treatment as the four Åsgard partners with respect to the disputed issues. On the basis of the declaration, the MPE alleged the right to compensation and initiated legal proceedings against Statoil on 29 April 2008 in a writ involving a multi-component claim. The aggregate principal exposure for the claim is estimated to be between NOK 4 and 7 billion after tax. Following a verdict in Stavanger district court on 15 January 2010, Statoil and the MPE on 5 March 2010 reached an amicable settlement of the case in which both parties waived their rights to appeal the court verdict. Under the settlement Statoil agreed to pay the MPE a cash compensation of NOK 500 million after tax, and NOK 375 million in pre-tax interest, corresponding to NOK 270 million after tax.

During the fourth quarter of 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. The dispute with ExxonMobil was settled in October 2009. The impact of this settlement on the Consolidated financial statements was not material.

Statoil was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to Statoil as of 1 October 2007 as part of the merger with Hydro Petroleum, and which could be in conflict with applicable Norwegian and US anti-corruption legislation. Following a preliminary assessment by Statoil, an external review of the relevant aspects was initiated. The external US and Norwegian legal counsels that have conducted the review delivered their report to Statoil ASA's CEO on 6 October 2008. The report has also been delivered to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), the US Department of Justice, the US Securities and Exchange Commission and Libyan authorities. The report does not draw any legal conclusions. In accordance with the mandate for the review, the report entails the facts relevant to applicable Norwegian and US anti-corruption legislation to which Statoil ASA may be subject as a result of the merger. Økokrim informed on 15 May 2009 that there will be no investigation related to the international activities of former Hydro Oil & Energy. Neither US authorities nor Libyan authorities have as of today initiated any steps in relation to the matters described in the investigation reports.

During the normal course of its business Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its financial statements for probable liabilities related to litigation and claims based on the group's best judgement. Statoil does not expect that the financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

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. 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 a normal arm's length basis.

The ownership interests of the Norwegian State in Statoil are administrated by the Norwegian Ministry of Petroleum and Energy (MPE). The following transactions with SDFI volumes were made between Statoil and MPE for the years presented:

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 74,338 million (204 million barrels oil equivalents), NOK 112,682 million (223 million barrels oil equivalents) and NOK 98,498 million (237 million barrels oil equivalents) in 2009, 2008 and 2007, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licenses) amounted to NOK 265 million, NOK 375 million and NOK 287 million in 2009, 2008 and 2007, respectively. The significant amounts included in the line item Payables to associated companies and other related parties in note 25 Trade and other payables, are amounts payable to the Norwegian State for these purchases.

The State's natural gas production, which Statoil is selling, in its own name, but for the Norwegian State's account and risk as well as related expenditures refunded by the State, are presented at net value in Statoil's financial statements.

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 unconsolidated affiliated entities. Such transactions are carried out on an arm's length basis, and are included within the applicable captions in the Statements of income.

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)	2009	2008	2007
Current benefits	50,573	50,949	44,463
Post-employment benefits	11,391	12,534	12,764
Other non-current benefits	137	129	111
Share based compensation benefits	444	278	94
Total	62,545	63,890	57,432

Loans to key management total less than NOK 0.2 million.

30 Financial instruments by category

Reclassification of derivative financial instruments
Statoil has, as further described in the Significant changes in accounting policies section of note 2 Significant accounting policies, in 2009 reclassified from current assets and liabilities to non-current assets and liabilities certain derivative financial instruments (mainly earn-out agreements, certain embedded derivative contracts and interest rate swap agreements) classified as held for trading in accordance with IAS 39 Financial instruments: Recognition and Measurement, as provided for in the amended version of IAS 1 Presentation of Financial Statements, which became effective 1 January 2009. This affects the classification between current and non-current assets and liabilities of the line items, "Derivative financial instruments". The following table sets forth the restatement of derivative financial instruments between current assets and liabilities and non-current assets and liabilities in the 31 December and 1 January 2008 balance sheets.

(in NOK million)	As earlier reported	Reclassification	As reclassified
31 December 2008			
Non-current assets			
Derivative financial instruments	2,383	18,899	21,282
Total non-current assets	433,611	18,899	452,510
Current assets			
Derivative financial instruments	27,505	(18,139)	9,366
Total current assets	144,812	(18,139)	126,673
TOTAL ASSETS	578,423	760	579,183
Non-current liabilities			
Derivative financial instruments	0	1,617	1,617
Total non-current liabilities	202,647	1,617	204,264
Current liabilities			
Derivative financial instruments	20,752	(857)	19,895
Total current liabilities	159,721	(857)	158,864
TOTAL EQUITY AND LIABILITIES	578,423	760	579,183

(in NOK million)	As earlier reported	Reclassified	As restated
1 January 2008			
Non-current assets			
Derivative financial instruments	609	12,159	12,768
Total non-current assets	353,428	12,159	365,587
Current assets			
Derivative financial instruments	21,093	(12,291)	8,802
Total current assets	129,790	(12,291)	117,499
TOTAL ASSETS	483,218	(132)	483,086
Non-current liabilities			
Derivative financial instruments	0	27	27
Total non-current liabilities	174,788	27	174,815
Current liabilities			
Derivative financial instruments	7,632	(159)	7,473
Total current liabilities	129,363	(159)	129,204
TOTAL EQUITY AND LIABILITIES	483,218	(132)	483,086

Financial instruments by IAS 39 category

The following tables provide a view of financial instruments and their carrying amounts as defined by IAS 39 categories. 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 Non-current financial liabilities for fair value information of non-current financial liabilities.

See also 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	Held for trading	Hedge accounting	Fair value option	Non-financial assets	Total carrying amount
31 December 2009								
Assets								
Non-current financial investments	16	-	2,223	-	-	11,044	-	13,267
Non-current derivative financial instruments	31	-	-	17,644	-	-	-	17,644
Non-current financial receivables	16	3,164	-	-	-	-	2,583	5,747
Current trade and other receivables	18	53,007	-	-	-	-	5,888	58,895
Current derivative financial instruments	31	-	-	5,369	-	-	-	5,369
Current financial investments	19	55	-	1,962	-	5,005	-	7,022
Cash and cash equivalents	20	24,723	-	-	-	-	-	24,723
Total		80,949	2,223	24,975	-	16,049	8,471	132,667

(in NOK million)	Note	Loans and receivables	Available-for-sale	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	Non-financial assets	Total carrying amount
31 December 2008								
Assets								
Non-current financial investments	16	-	4,164	-	-	12,301	-	16,465
Non-current derivative financial instruments	31	-	-	18,899	2,383	-	-	21,282
Non-current financial receivables	16	2,771	-	-	-	-	2,143	4,914
Current trade and other receivables	18	66,644	-	-	-	-	3,287	69,931
Current derivative financial instruments	31	-	-	9,297	69	-	-	9,366
Current financial investments	19	15	-	7,874	-	1,858	-	9,747
Cash and cash equivalents	20	18,638	-	-	-	-	-	18,638
Total		88,068	4,164	36,070	2,452	14,160	5,430	150,343

(in NOK million)	Note	Loans and receivables	Available-for-sale	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	Non-financial assets	Total carrying amount
1 January 2008								
Assets								
Non-current financial investments	16	-	3,291	-	-	11,975	-	15,266
Non-current derivative financial instruments	31	-	-	12,159	609	-	-	12,768
Non-current financial receivables	16	3,515	-	-	-	-	-	3,515
Current trade and other receivables	18	69,378	-	-	-	-	-	69,378
Current derivative financial instruments	31	-	-	8,760	42	-	-	8,802
Current financial investments	19	-	-	3,359	-	-	-	3,359
Cash and cash equivalents	20	18,264	-	-	-	-	-	18,264
Total		91,157	3,291	24,278	651	11,975	-	131,352

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2009						
Liabilities						
Non-current financial liabilities	22	95,962	-	-	-	95,962
Non-current derivative financial instruments	31	-	-	1,657	-	1,657
Current trade and other payables	25	58,048	-	-	1,753	59,801
Current financial liabilities	26	8,150	-	-	-	8,150
Current derivative financial instruments	31	-	-	2,860	-	2,860
Total		162,160	-	4,517	1,753	168,430

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
31 December 2008						
Liabilities						
Non-current financial liabilities	22	52,065	2,541	-	-	54,606
Non-current derivative financial instruments	31	-	-	1,617	-	1,617
Current trade and other payables	25	58,990	-	-	2,210	61,200
Current financial liabilities	26	20,695	-	-	-	20,695
Current derivative financial instruments	31	-	-	19,895	-	19,895
Total		131,750	2,541	21,512	2,210	158,013

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Non-financial liabilities	Total carrying amount
1 January 2008						
Liabilities						
Non-current financial liabilities	22	43,649	724	-	-	44,373
Non-current derivative financial instruments	31	-		27	-	27
Current trade and other payables	25	64,624	-	-	-	64,624
Current financial liabilities	26	6,166	-	-	-	6,166
Current derivative financial instruments	31	-	-	7,473	-	7,473
Total		114,439	724	7,500	-	122,663

The following tables include amounts from the Consolidated statements of income related to financial instruments.

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans & 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	-	-	-	-	(159)	109,462	121,640
Net financial items								
Net foreign exchange gains (losses)	16,661	-	-	(10,568)	(4,076)	-	(24)	1,993
Interest income	1,290	-	326	1,088	-	-	-	2,704
Other financial items	518	-	403	111	-	(28)	-	1,004
Interest income and other financial items	1,808	-	729	1,199	-	(28)	-	3,708
Interest expenses	2,123	-	-	-	(3,748)	-	-	(1,625)
Impairment loss recognised	-	-	-	-	-	(1,404)	-	(1,404)
Other financial expenses	(6,807)	-	-	-	(183)	-	(2,432)	(9,422)
Interest and other financial expenses	(4,684)	-	-	-	(3,931)	(1,404)	(2,432)	(12,451)
Net financial items	13,785	-	729	(9,369)	(8,007)	(1,432)	(2,456)	(6,750)
Total	26,122	-	729	(9,369)	(8,007)	(1,591)	107,006	114,890

	Fair value through profit or loss							
(in NOK million)	Held for trading	Hedge accounting	Fair value option	Loans & receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2008								
Net operating income	19,917	-	-	-	-	(346)	179,261	198,832
Net financial items								
Net foreign exchange gains (losses)	(24,266)	-	-	3,848	(12,145)	-	-	(32,563)
Interest income	3,230	-	437	3,392	-	-	-	7,059
Other financial items	6,006	-	(971)	52	-	61	-	5,148
Interest income and other financial items	9,236	-	(534)	3,444	-	61	-	12,207
Interest expenses	959	-	-	-	(2,243)	-	-	(1,284)
Other financial expenses	5,660	(27)	-	-	(251)	-	(2,107)	3,275
Interest and other financial expenses	6,619	(27)	-	-	(2,494)	-	(2,107)	1,991
Net financial items	(8,411)	(27)	(534)	7,292	(14,639)	61	(2,107)	(18,365)
Total	11,506	(27)	(534)	7,292	(14,639)	(285)	177,154	180,467

(in NOK million)	Fair value through profit or loss: Held for trading	Hedge accounting	Fair value option	Loans & receivables	Financial liabilities at amortised cost	Available-for-sale assets	Non-financial assets or liabilities	Total
For the year ended 31 December 2007								
Net operating income	(2,043)	-	-	-	-	129	139,118	137,204
Net financial items								
Net foreign exchange gains (losses)	9,092	-	-	(8,516)	9,467	-	-	10,043
Interest income	234	-	281	1,390	-	-	-	1,905
Other financial items	(313)	-	(185)	541	-	357	-	400
Interest income and other financial items	(79)	-	96	1,931	-	357	-	2,305
Interest expenses	(379)	-	-	-	(584)	-	-	(963)
Other financial expenses	504	9	-	-	(192)	-	(2,099)	(1,778)
Interest and other financial expenses	125	9	-	-	(776)	-	(2,099)	(2,741)
Net financial items	9,138	9	96	(6,585)	8,691	357	(2,099)	9,607
Total	7,095	9	96	(6,585)	8,691	486	137,019	146,811

31 Financial instruments: measurement and market risk sensitivities

Fair value hedges

The fair value hedge relationships for which Statoil in 2007 and 2008 applied hedge accounting have been discontinued since the group revoked the designation in the first quarter of 2009. The fair value adjustment total of NOK 2.5 billion recognised in the Consolidated balance sheet at 31 December 2008 is being amortised over the remaining duration, 14 to 19 years, of the loans that were originally identified as hedging objects in these hedge relationships.

Fair value measurement of financial instruments

Derivative financial instruments

Statoil recognises all derivative financial instruments in the balance sheet at fair value. Changes in the fair value of the derivative financial instruments are recognised in the 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 calculating fair value of derivative financial instruments Statoil uses prices quoted in an active market for identical assets to the extent possible. When such prices are not available Statoil uses inputs that are observable either directly or indirectly. The valuation techniques most frequently used by Statoil when valuing derivative financial instruments are mark to market calculation or a net present value calculation of expected future cash flows. For more information about the methodology and assumption used when calculating 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 2009 NOK 13.0 billion relates to certain earn-out agreements and embedded derivatives recognised as derivative financial instruments in accordance with IAS 39. At the end of 2008 the estimated fair value of these agreements was NOK 9.4 billion.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
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
At 31 December 2008			
Debt-related instruments	13,083	(989)	12,094
Non-debt-related instruments	403	(14,032)	(13,629)
Crude oil and refined products	13,136	(2,491)	10,645
Natural gas and electricity	4,026	(4,000)	26
Total	30,648	(21,512)	9,136

Financial investments

Statoil recognises all financial investments in the balance sheet 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. The group 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 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 Statement of comprehensive income, while any impairment losses are recognised in the Statement of income within Net financial items.

When calculating fair value of financial investments, the group uses prices quoted in an active market for identical assets 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 net present value calculations of expected future cash flows. For more information about methodology and assumptions used when calculating fair value of the group'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 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 the group's basis for fair value measurement.

(in NOK million)	Non-current financial investments	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	Total fair value
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 price inputs other than quoted prices but are from observable market transactions (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
At 31 December 2008							
Fair value based on prices quoted in an active market for identical assets or liabilities (Level 1)	6,402	0	1,744	399	0	(544)	8,001
Fair value based on price inputs other than quoted prices but are from observable market transactions (Level 2)	6,575	12,430	8,003	7,648	(857)	(19,260)	14,539
Fair value based on unobservable inputs (Level 3)	3,488	8,852	0	1,319	(760)	(91)	12,808
Total fair value	16,465	21,282	9,747	9,366	(1,617)	(19,895)	35,348

The first level in the above table, 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 calculated based on observable prices on identical instruments. This category will, in most cases, only be relevant for exchange traded financial instruments.

The second level in the above table, Fair value based on price inputs, other than quoted prices, which are derived from observable market transactions, includes Statoil's non-standardised contracts for which fair values are calculated 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.

The third level in the above table, Fair value based on unobservable inputs, includes financial instruments for which fair values are calculated 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 major part of the fair value of certain earn-out agreements and embedded derivative contracts are calculated with price inputs from observable market transactions. They have been classified in their entirety in the third category within Current and Non-current derivative financial instruments - assets in the above table, as the value is partly derived from internally generated assumptions. Another reasonable assumption, which could have been used when calculating the fair value of these contracts, could be to extrapolate the last observed forward prices. By extrapolating the forward curves with inflation, the fair value of the contracts included would have increased by approximately NOK 1.5 billion. Such a change in fair value would have been recognised in the Statement of income.

The reconciliation of the changes in fair value during 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 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)

Practically all gains and losses recognised in the Statement of income during 2009 are related to assets and liabilities held by the group at the end of 2009.

Certain divestment requirements were set out by the European Commission (EC) in relation to Statoil's acquisition of the Jet automated petrol retail station network in 2008. As a consequence the investment was classified as an available for sale asset at end 2008. During 2009 the divestment requirements have been fulfilled. By end of 2009 the remaining Jet activity is fully consolidated and the values previously included in level 3 in the above table have been transferred out.

Market risk sensitivities

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 6 Financial risk management.

Statoil's assets and liabilities resulting from commodity based derivatives contracts are mainly related to non-exchange traded derivative instruments, including embedded derivatives that in accordance with IAS 39 have been bifurcated and recognised with fair value in the balance sheet.

Price risk sensitivities by end of 2009 have been calculated by assuming a 30% change in crude oil, refined products and electricity prices, and 50% for natural gas prices. Compared to the sensitivities calculated by end of 2008 and 2007, the group's assessment of what are reasonably possible changes in the commodity prices for the coming year, have been changed following an assessment of the recent developments in the markets in which Statoil operates. By end of 2008 and 2007 these sensitivities were calculated by assuming a 50% and 10% change respectively.

Since none of the derivative financial instruments included in the table below are part of hedging relationships, any changes in the fair value will be recognised in the Statement of income.

(in NOK million)	Net fair value	-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)
		-50% sensitivity	50% sensitivity
At 31 December 2008			
Crude oil and refined products	10,645	(4,124)	4,440
Natural gas and electricity	26	3,447	(3,431)
		-10% sensitivity	10% sensitivity
At 31 December 2007			
Crude oil and refined products	8,582	(651)	652
Natural gas and electricity	(702)	1,530	(1,522)

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 Natural Gas and Manufacturing and Marketing segments.

Oil sales, trading and supply (OTS), within the Manufacturing and Marketing segment, uses the historical simulation method where daily percentage market price and volatility changes for all significant products in the OTS 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 revalued 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 12 month rolling observation window and input parameters such as simulation intervals are recalibrated when model performance moves outside acceptable bounds.

The Natural Gas segment 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 OTS and the Natural Gas segment to best reflect the nature of the relevant commodity markets.

Within OTS 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 2009 and 2008 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 2009			
Crude oil and refined products	189	42	103
Natural gas and electricity	219	8	80
For the year ended 31 December 2008			
Crude oil and refined products	143	28	79
Natural gas and electricity	218	40	116

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

Interest rate and currency risk

Interest rate and currency risks constitute significant financial risks for the Statoil group. 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 and currency risks and how the group manages these risks see note 6 Financial risk management.

By end of 2009 the following currency risk sensitivities have been calculated by assuming a 12 % change in foreign exchange rates that the group is exposed to. Compared to the sensitivities calculated by end of 2008 and 2007 the group's assessment of what are reasonably possible changes in foreign exchange rates for the coming year have been changed. By end of 2008 and 2007 a 20% and a 10% change respectively, was assumed in the calculation.

As of 1 January 2009 Statoil ASA's functional currency changed from NOK to USD, see note 1 Organisation. The change of functional currency has impacted the currency risk sensitivities when comparing 2009 with previous years.

(in NOK million)	USD	EUR	GBP	CAD	NOK	SEK	DKK
At 31 December 2009							
Net gains (losses) (12% sensitivity)	(3,589)	(323)	365	(299)	2,423	558	861
Net gains (losses) (-12% sensitivity)	3,589	323	(365)	299	(2,423)	(558)	(861)
At 31 December 2008							
Net gains (losses) (20% sensitivity)	(31,369)	(11,906)	11	(170)	39,856	1,976	1,636
Net gains (losses) (-20% sensitivity)	31,369	11,906	(11)	170	(39,856)	(1,976)	(1,636)
At 31 December 2007							
Net gains (losses) (10% sensitivity)	(9,391)	(3,541)	926	(297)	11,567	129	591
Net gains (losses) (-10% sensitivity)	9,391	3,541	(926)	297	(11,567)	(129)	(591)

For the interest rate risk sensitivity a 1.5 percentage point change in the interest rates have been used in the calculation. Compared to the sensitivities calculated by end of 2008 and 2007 Statoil's assessment of what are reasonably possible changes in interest rates that the group is exposed to for the coming year has been changed. By end of 2008 and 2007 a one percentage point change in the interest rates was used. 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 Statement of income are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2009		
Interest rate risk (1.5 percentage point sensitivity)	8,456	(8,456)
At 31 December 2008		
Interest rate risk (1 percentage point sensitivity)	3,395	(3,395)
At 31 December 2007		
Interest rate risk (1 percentage point sensitivity)	2,714	(2,714)

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 2009, as for 2008, the group's view is a 20% and 40% change in the equity price for the listed and non-listed equity securities respectively. In 2007 a 10% change in the equity price was used.

For the listed equity securities changes in fair values would be recognised as gains or losses in the 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 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 2009			
Listed equity securities	4,318	(864)	864
At 31 December 2008			
Listed equity securities	2,276	(455)	455

(in NOK million)	Fair value	-40% sensitivity	40% sensitivity
At 31 December 2009			
Non-listed equity securities	2,223	(889)	889
At 31 December 2008			
Non-listed equity securities	4,205	(1,682)	1,682

(in NOK million)	Fair value	-10% sensitivity	10% sensitivity
At 31 December 2007			
Listed equity securities	4,230	(423)	423
Non-listed equity securities	3,291	(329)	329

32 Merger with Hydro Petroleum

The shareholders of Statoil ASA and Norsk Hydro ASA (Hydro) at extraordinary General Meetings on 5 July 2007 approved a merger between Statoil ASA and the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). The merger was effective 1 October 2007.

As a result of the merger in 2007 Statoil's share capital increased by NOK 2,606,655,590 from NOK 5,364,962,167.50 to NOK 7,971,617,757.50 from the issuing of 1,042,662,236 shares with a nominal value of NOK 2.50 to Hydro's shareholders. Hydro's shareholders received 0.8622 shares in the merged company for each Hydro share. After the increase Hydro's shareholders held 32.7% and former Statoil's shareholders held 67.3% of the merged company, Statoil ASA.

Given that both Statoil ASA and Norsk Hydro ASA were under the control of the Norwegian State, the merger was accounted for as a business combination between entities under common control. Management concluded that for a merger of entities under common control, the most meaningful portrayal for accounting purposes was to combine Statoil and Hydro Petroleum using the carrying amounts of assets and liabilities and restating the financial statements for all periods presented as if the companies had always been combined. Consistent with this accounting treatment, the financial statements of Hydro Petroleum were adjusted to conform to the accounting policies of Statoil ASA for the tax benefit of uplift in Norway, the sales method of accounting for revenues for over- and underlift in the production of oil and gas and pension accounting. The combined impact of these changes was to decrease net equity by approximately NOK 3 billion for the year ended 31 December 2006.

Under provisions of the merger plan, an inter-company balance was established between former Statoil and Norsk Hydro ASA as of 31 December 2006 that provides that debt less cash and short term investments of Hydro Petroleum be set at a defined level by an adjustment to a merger payable or receivable between the companies. This resulted in Statoil having a merger receivable from Norsk Hydro ASA that was included in the 2007 cash flows upon its settlement.

Hydro Petroleum was not a separate legal entity from Hydro and, therefore, had combined cash and equity balances with Hydro. As a consequence in accounting for the merger, certain cash flows to or from Hydro were treated as equity distributions or injections to or from Hydro. This is reflected in the Consolidated statements of cash flows as "Norsk Hydro ASA merger balance" and in the Consolidated shareholders equity of Statoil as "Merger related adjustments", see the Consolidated statement of changes in equity.

Statoil, subsequent to the merger, recorded a total expense in 2007 of NOK 10.7 billion before tax related to restructuring expenses and other expenses related to the merger. The major part of these expenses was related to pensions and early retirement packages offered to employees in Statoil ASA above the age of 58 years (contingent upon certain conditions).

33 Subsequent events

Statoil's board of directors has approved a proposal to create a stand-alone Energy & Retail (E&R) business through an initial public offering (IPO) on the Oslo Stock Exchange. The IPO will take place at the earliest in the fourth quarter of 2010 or at a time when the capital market is deemed favourable for such an offering.

Statoil intends to remain a majority shareholder of E&R at the time of the initial public offering and listing. The size and time horizon of Statoil's future ownership in E&R will be tailored to support and develop company value both for E&R and for the Statoil Group.

34 Supplementary oil and gas information (unaudited)

In accordance with FASB Accounting Standards Codification "Extractive Activities - Oil and Gas" (Topic 932), Statoil is making certain supplemental disclosures about oil and gas exploration and production operations as 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.

Financial Accounting Standard Board aligned in January 2010 the oil and gas reserves estimation and disclosure requirements of "Extractive Activities - Oil and Gas" (Topic 932) with the requirements in the Securities and Exchange Commission's final rule, "Modernization of the Oil and Gas Reporting Requirements" (the Final Rule) issued December 2008. Our reporting in 2009 is in accordance with the updated requirements. Prior period disclosures are not adjusted. For further information regarding revision of 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 2009 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 US Securities and Exchange Commission (SEC), Rule 4-10 of Regulation S-X. Reserves are net of royalty oil paid in kind and quantities consumed during production. 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.

In 2002, Statoil entered into a buy-back contract in Iran. Statoil also participates in a number of production sharing agreements (PSAs) in Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia. Reserves from such agreements are based on the volumes to which Statoil has access (cost oil and profit oil), limited to available market access. Proved reserves at end of year associated with PSA and buy-back agreements are disclosed separately in the following tables.

Statoil is recording, as proved reserves, volumes equivalent to our tax liabilities payable in-kind under negotiated fiscal arrangements (production sharing agreements or income sharing agreements).

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. Reserves at year-end 2009 have been determined based on a 12-month average 2009 Brent price equivalent to $59.9/bbl. The increase in oil price from year end 2008 (Brent blend price of $36.6/bbl) to an average 2009 price 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. The gas prices have in general, decreased from year end 2008 to an average 2009 price and has 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 required, on behalf of the Norwegian State's direct financial interest (SDFI), to manage, transport and sell the Norwegian State's oil and gas. These reserves are sold in conjunction with our own reserves. As part of this arrangement, Statoil will deliver gas to customers in accordance with various types of sales contracts. In order to fulfil the commitments, Statoil will utilise 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 supply volumes. For sales of the SDFI natural gas, both to Statoil and to third parties, the payment to the Norwegian State is based on either achieved prices, a net back formula calculated price or market value. All of the Norwegian State's oil and NGL is acquired by Statoil. Pricing of the crude oil is based on market reflective prices; NGL prices are either based on achieved prices, market value or market reflective prices.

The owner's instruction 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 80% of total proved reserves at 31 December 2009 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 America.

The following tables reflect the estimated proved reserves of oil and gas at 31 December 2006 to 2009, and the changes therein.

	Net proved oil and NGL reserves in million barrels			Net proved gas reserves in billion standard cubic feet			Net proved oil, NGL and gas reserves in million barrels oil equivalent		
	Norway	Outside Norway	Total	Norway	Outside Norway	Total	Norway	Outside Norway	Total
Reserves in consolidated companies									
At 31 December 2006	1,667	756	2,423	19,129	1,567	20,696	5,068	1,032	6,101
Of which:									
Proved developed reserves	1,188	334	1,523	13,378	283	13,661	3,566	385	3,951
Proved reserves under PSA and buy-back agreements	0	441	441	0	1,169	1,169	0	649	649
Production from PSA and buy-back agreements	0	47	47	0	56	56	0	57	57
Revisions and improved recovery	197	16	214	598	(27)	571	311	14	325
Extensions and discoveries	38	105	143	405	0	405	110	105	215
Purchase of reserves-in-place	0	0	0	0	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0	0	0	0	0
Production	(299)	(92)	(391)	(1,238)	(114)	(1,352)	(519)	(112)	(632)
At 31 December 2007	1,604	785	2,389	18,893	1,426	20,319	4,971	1,039	6,010
Of which:									
Proved developed reserves	1,187	323	1,510	15,084	748	15,832	3,875	456	4,331
Proved reserves under PSA and buy-back agreements	0	387	387	0	977	977	0	561	561
Production from PSA and buy-back agreements	0	67	67	0	80	80	0	82	82
Revisions and improved recovery	81	95	177	7	141	148	83	120	203
Extensions and discoveries	12	0	12	29	0	29	17	0	17
Purchase of reserves-in-place	0	69	69	0	0	0	0	69	69
Sales of reserves-in-place	0	(3)	(3)	0	(43)	(43)	0	(10)	(10)
Transfer to associated company *	0	(191)	(191)	0	0	0	0	(191)	(191)
Production	(302)	(78)	(380)	(1,348)	(121)	(1,469)	(542)	(100)	(642)
At 31 December 2008	1,396	677	2,074	17,581	1,403	18,984	4,529	927	5,456
Of which:									
Proved developed reserves	1,113	381	1,494	14,482	727	15,209	3,693	510	4,204
Proved reserves under PSA and buy-back agreements	0	433	433	0	1,106	1,106	0	630	630
Production from PSA and buy-back agreements	0	66	66	0	88	88	0	82	82

	Net proved oil reserves in million barrels			Net proved gas reserves in billion standard cubic feet			Net proved oil and gas reserves in million barrels oil equivalent		
	Norway	Outside Norway	Total	Norway	Outside Norway	Total	Norway	Outside Norway	Total
Reserves in associated companies									
Remaining reserves after transfer*	0	123	123	0	0	0	0	123	123
Revisions and improved recovery	0	11	11	0	0	0	0	11	11
Production	0	(6)	(6)	0	0	0	0	(6)	(6)
At 31 December 2008	0	127	127	0	0	0	0	127	127
Total Proved Reserves including reserves in associated companies at 31 December 2008	1,396	805	2,201	17,581	1,403	18,984	4,529	1,055	5,584
Of which:									
Proved developed reserves	1,113	406	1,519	14,482	727	15,209	3,693	536	4,229

*Sincor to Petrocedeño; reduction from 15% to 9.677% interest

The transformation process of the Sincor joint venture in Venezuela, into the new mixed company Petrocedeño was finalised in February 2008 reducing Statoil's shareholding interest from 15.0 % in the Sincor joint venture to 9.677 % in Peterocedeño. The change in Statoil share resulted in a reduction of proved reserves corresponding to 68 million boe in 2008.

Statoil acquired Anadarco's 50.0% share in Peregrino, Brazil, in 2008 resulting in a 100% ownership of the asset, and becoming the operator. The related increase in proved reserves was 69 million boe.

	Norway	Eurasia excluding Norway	Net proved oil and NGL reserves in million barrels Africa	America	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	0	0	0	0	0
Sales of reserves-in-place	0	(4)	0	0	(4)
Production	(279)	(19)	(63)	(15)	(376)
At 31 December 2009	1,351	138	310	272	2,070
Of which:					
Proved developed reserves	1,028	94	208	83	1,413
Proved reserves under PSA and buy-back agreements	0	124	310	0	434
Production from PSA and buy-back agreements	0	17	63	0	80
Reserves in associated companies					
At 31 December 2008	0	0	0	127	127
Revisions and improved recovery	0	0	0	(18)	(18)
Extensions and discoveries	0	0	0	0	0
Purchase of reserves-in-place	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0
Production	0	0	0	(5)	(5)
At 31 December 2009	0	0	0	105	105
Total Proved Oil and NGL Reserves including reserves in associated companies at 31 December 2009	1,351	138	310	376	2,174
Of which:					
Proved developed reserves	1,028	94	208	111	1,442

	Net proved gas reserves in billion standard cubic feet				
	Norway	Eurasia excluding Norway	Africa	America	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	0	0	87	122
Purchase of reserves-in-place	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0
Production	(1,367)	(49)	(54)	(48)	(1,519)
At 31 December 2009	16,938	747	338	125	18,148
Of which:					
Proved developed reserves	14,138	523	256	73	14,990
Proved reserves under PSA and buy-back agreements	0	548	338	0	886
Production from PSA and buy-back agreements	0	46	54	0	101
Reserves in associated companies					
At 31 December 2008	0	0	0	0	0
Revisions and improved recovery	0	0	0	0	0
Extensions and discoveries	0	0	0	0	0
Purchase of reserves-in-place	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0
Production	0	0	0	0	0
At 31 December 2009	0	0	0	0	0
Total Proved Gas Reserves including reserves in associated companies at 31 December 2009	16,938	747	338	125	18,148
Of which:					
Proved developed reserves	14,138	523	256	73	14,990

	Net proved oil, NGL and gas reserves in million barrels oil equivalent				
	Norway	Eurasia excluding Norway	Africa	America	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	0	0	0	0	0
Sales of reserves-in-place	0	(4)	0	0	(4)
Production	(523)	(28)	(73)	(24)	(647)
At 31 December 2009	4,369	271	370	294	5,304
Of which:					
Proved developed reserves	3,548	187	254	96	4,084
Proved reserves under PSA and buy-back agreements	0	222	370	0	592
Production from PSA and buy-back agreements	0	25	73	0	98
Reserves in associated companies					
At 31 December 2008	0	0	0	127	127
Revisions and improved recovery	0	0	0	(18)	(18)
Extensions and discoveries	0	0	0	0	0
Purchase of reserves-in-place	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0
Production	0	0	0	(5)	(5)
At 31 December 2009	0	0	0	105	105
Total Proved Reserves including reserves in associated companies at 31 December 2009	4,369	271	370	398	5,408
Of which:					
Proved developed reserves	3,548	187	254	124	4,113

Statoil's proved reserves of extra heavy oil in Venezuela and Canada are included as oil in the tables above.

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)	2009	At 31 December 2008	2007
Unproved Properties	49,497	61,484	40,513
Proved Properties, wells, plants and other equipment	655,886	611,251	526,634
Total Capitalised cost	705,383	672,735	567,147
Accumulated depreciation, depletion, amortisation and valuation allowances	(379,575)	(349,428)	(309,527)
Net Capitalised cost	325,808	323,307	257,620

Net capitalised cost related to associated companies as of 31 December 2009 was NOK 3.7 billion, NOK 4.6 billion in 2008 and 0 in 2007.

Expenditures incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

These expenditures include both amounts capitalised and expensed for 2009.

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	America	Total
Year ended 31 December 2009					
Exploration costs	8,170	1,310	2,465	4,950	16,895
Development costs 1)	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 Property Acquisition, Exploration and Development Activities

These expenditures include both amounts capitalised and expensed in 2008 and 2007

(in NOK million)	Norway	Outside Norway	Total
Year ended 31 December 2008			
Exploration costs	8,672	9,136	17,808
Development costs [1)]	29,478	14,215	43,693
Acquired proved properties [2)]	0	12,435	12,435
Acquired unproved properties [3)]	1,255	12,323	13,578
Total	39,405	48,109	87,514
Year ended 31 December 2007			
Exploration costs	5,749	8,499	14,248
Development costs [1)]	28,428	13,330	41,758
Acquired unproved properties	0	17,133	17,133
Total	34,177	38,962	73,139

(1) Includes minor development costs in unproved properties.

(2) Includes the acquisition of Anadarco's 50% share in Peregrino, Brazil.

(3) Includes signature bonuses and the acquisition of a share in Goliat and Marcellus shale gas development.

Expenditures incurred in Oil and Gas Development Activities related to associated companies in 2009 was NOK 286 million, NOK 448 million in 2008 and 0 in 2007.

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 Statoil's segment disclosures in note 5 Segments to the financial statements but excluded from the table below relates to gas trading activities, commodity based derivatives, transportation, business development as well as effects of disposals 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 overhead.

Consolidated companies

(in NOK million)	Norway	Eurasia excluding Norway	Africa	America	Total
Year ended 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 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

(in NOK million)	Norway	Outside Norway	Total
Year ended December 2008			
Sales	151	8,274	8,425
Transfers	216,809	34,718	251,527
Total revenues	216,960	42,992	259,952
Exploration expense	(5,536)	(9,157)	(14,693)
Production costs	(19,744)	(6,009)	(25,753)
Depreciation, depletion and amortisation (DD&A)	(24,043)	(13,689)	(37,732)
Total costs	(49,323)	(28,855)	(78,178)
Results of operations before tax	167,637	14,137	181,774
Tax expense	(124,564)	(9,710)	(134,274)
Result of operations	43,073	4,427	47,500
Year ended December 2007			
Sales	36	13,064	13,100
Transfers	173,238	27,705	200,943
Total revenues	173,274	40,769	214,043
Exploration expense	(3,638)	(7,695)	(11,333)
Production costs	(22,793)	(7,132)	(29,925)
DD&A	(23,030)	(11,103)	(34,133)
Total costs	(49,461)	(25,930)	(75,391)
Results of operations before tax	123,813	14,839	138,651
Tax expense	(92,058)	(4,327)	(96,385)
Result of operations	31,754	10,512	42,266

The results of operations for oil and gas producing activities of equity method investees outside of Norway amounts to NOK 26 million in the year ended December 2009, NOK 428 million in the year ended December 2008 and NOK 0 in the year ended December 2007.

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 for 2009 and year end market prices for 2008 and 2007 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	America	Total
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
Associated companies					
Standardised measure of discounted future net cash flows	0	0	0	2,097	2,097
Total Standardised measure of discounted future net cash flows including associated companies	112,500	16,048	25,252	22,439	176,239

(in NOK million)	Norway	Outside Norway	Total
At 31 December 2008			
Consolidated companies			
Future net cash inflows	1,738,693	204,808	1,943,501
Future development costs	(109,456)	(44,920)	(154,376)
Future production costs	(412,340)	(77,398)	(489,738)
Future income tax expenses	(919,740)	(30,118)	(949,858)
Future net cash flows	297,157	52,372	349,529
10 % annual discount for estimated timing of cash flows	(150,919)	(15,019)	(165,938)
Standardised measure of discounted future net cash flows	146,238	37,353	183,591
Associated companies			
Standardised measure of discounted future net cash flows	0	2,024	2,024
Total standardised measure of discounted future net cash flows including associated companies	146,238	39,377	185,615
At 31 December 2007			
Future net cash inflows	1,788,440	429,335	2,217,775
Future development costs	(107,966)	(57,332)	(165,298)
Future production costs	(338,834)	(102,838)	(441,672)
Future income tax expenses	(1,009,179)	(97,850)	(1,107,029)
Future net cash flows	332,461	171,315	503,776
10 % annual discount for estimated timing of cash flows	(135,717)	(67,289)	(203,006)
Standardised measure of discounted future net cash flows	196,744	104,026	300,770

Changes in the standardised measure of discounted future net cash flows from proved reserves

(in NOK million)	2009	2008	2007
Consolidated companies			
Standardised measure at beginning of year	183,591	300,770	245,714
Net change in sales and transfer prices and in production (lifting) costs related to future production	(288,973)	(74,453)	239,091
Changes in estimated future development costs	(48,980)	(56,924)	(30,740)
Sales and transfers of oil and gas produced during the period, net of production cost	(179,072)	(234,199)	(189,992)
Net change due to extensions, discoveries, and improved recovery	9,403	1,866	15,967
Net change due to purchases and sales of minerals in place	(530)	(4,936)	0
Net change due to revisions in quantity estimates	101,298	51,574	78,122
Previously estimated development costs incurred during the period	56,900	56,128	41,758
Accretion of discount	214,065	50,960	(54,374)
Net change in income taxes	126,440	92,805	(44,776)
Total change in the standardised measure during the year	(9,449)	(117,179)	55,056
Standardised measure at end of year	174,142	183,591	300,770
Associated companies			
Standardised measure at end of year	2,097	2,024	0
Standardised measure at end of year including associated companies	176,239	185,615	300,770

Financial statements for Statoil ASA

STATEMENT OF INCOME STATOIL ASA - NGAAP

(in NOK million)	Note	2009	2008
REVENUES AND OTHER INCOME			
Revenues	5	313,194	559,493
Net income from subsidiaries and associated companies	13	28,431	27,950
Other income		5	979
Total revenues and other income		341,630	588,422
OPERATING EXPENSES			
Purchases [net of inventory variation]		(294,442)	(360,894)
Operating expenses		(10,649)	(39,353)
Selling, general and administrative expenses		(7,765)	(11,469)
Depreciation, amortisation and net impairment losses	12	(814)	(19,494)
Exploration expenses		(861)	(3,956)
Total operating expenses		(314,531)	(435,166)
Net operating income		27,099	153,256
FINANCIAL ITEMS			
Net foreign exchange gains (losses)		10,608	(38,319)
Interest income and other financial items		4,693	10,450
Interest and other finance expenses		(5,491)	(5,441)
Net financial items	10	9,810	(33,310)
Income before tax		36,909	119,946
Income tax	11	(8,032)	(79,309)
Net income		28,878	40,637

BALANCE SHEET STATOIL ASA - NGAAP

(in NOK million)	Note	At 31 December 2009	At 31 December 2008
ASSETS			
Non-current assets			
Property, plant and equipment	12	4,771	136,312
Intangible assets		29	5,110
Investments in subsidiaries	13	257,634	281,045
Investments in associated companies	13	605	1,040
Deferred tax assets	11	2,722	0
Pension assets	20	2,665	0
Financial assets	14	1,296	574
Receivables on subsidiaries	14	47,651	44,188
Total non-current assets		317,373	468,269
Current assets			
Inventories	15	11,976	6,820
Trade and other receivables	16	32,053	44,455
Receivables on subsidiaries		44,726	10,921
Current tax receivable	11	109	2,823
Derivative financial instruments	3	763	2,091
Financial investments	14	1,905	2,616
Cash and cash equivalents	17	14,460	6,272
Total current assets		105,992	75,998
TOTAL ASSETS		423,365	544,267

BALANCE SHEET STATOIL ASA - NGAAP

(in NOK million)	Note	At 31 December 2009	At 31 December 2008
EQUITY AND LIABILITIES			
Equity			
Share capital		7,972	7,972
Treasury shares		(15)	(9)
Additional paid-in capital		17,330	17,330
Retained earnings		98,060	97,078
Reserves for valuation variances		51,523	60,095
Total equity	18	174,870	182,466
Non-current liabilities			
Financial liabilities	19	80,129	44,951
Derivative financial instruments	3	1,443	0
Liabilities to subsidiaries		50	37
Deferred tax liabilities	11	0	34,942
Pension liabilities	20	20,682	24,961
Asset retirement obligations, other provisions and other liabilities	21	1,048	26,250
Total non-current liabilities		103,352	131,141
Current liabilities			
Trade and other payables	22	25,466	33,641
Current tax payable	11	3,668	32,643
Financial liabilities	23	7,386	19,039
Derivative financial instruments	3	1,658	15,878
Dividends payable		19,100	23,090
Liabilities to subsidiaries		87,865	106,369
Total current liabilities		145,143	230,660
Total liabilities		248,495	361,801
TOTAL EQUITY AND LIABILITIES		423,365	544,267

STATEMENT OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2009	2008
OPERATING ACTIVITIES		
Income before tax	36,909	119,946
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortisation and net impairment losses	814	19,494
Exploration expenditures written off	0	354
(Gains) losses on foreign currency transactions and balances	397	11,840
(Gains) losses on sales of assets and other items	(12,963)	(22,209)
Changes in working capital (other than cash and cash equivalents):		
· (Increase) decrease in inventories	(6,185)	1,488
· (Increase) decrease in trade and other receivables	12,416	(169)
· (Increase) decrease in net current financial derivative instruments	(12,892)	12,557
· (Increase) decrease in current financial investments	711	(2,461)
· Increase (decrease) in trade and other payables	(3,165)	(11,899)
· Increase (decrease) in receivables/liabilities to/from subsidiaries	13,589	(531)
Taxes paid	(27,772)	(83,004)
(Increase) decrease in non-current items related to operating activities	(5,409)	1,056
Cash flows provided by operating activities	(3,550)	46,462
INVESTING ACTIVITIES		
Cash flows provided by (used in) investing activities	21,639	(97,092)
FINANCING ACTIVITIES		
New long-term borrowings	46,312	2,521
Repayment of long-term borrowings	(4,536)	(2,258)
Dividend paid	(23,085)	(27,082)
Treasury shares purchased	(343)	(308)
Net short-term borrowings, bank overdrafts and other	(6,369)	10,495
Increase (decrease) in financial receivables and payables to/from subsidiaries	(20,788)	73,510
Cash flows provided by financing activities	(8,809)	56,878
Net increase (decrease) in cash and cash equivalents	9,280	6,248
Effect of exchange rate changes on cash and cash equivalents	(1,092)	0
Cash and cash equivalents at the beginning of the period	6,272	24
Cash and cash equivalents at the end of the period	14,460	6,272
Interest paid	2,522	1,871
Interest received	3,007	6,439

1 Organisation and basis of presentation

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

Effective 1 October 2007, Statoil ASA merged with the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum), and the company's name changed to StatoilHydro ASA. As of 1 November 2009 the name was changed back to Statoil ASA. 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.

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. This group internal reorganisation significantly decreases the comparability of amounts between years for Statoil ASA and impacts the extent and content of the note disclosures in these Financial statements to a significant degree. All the following note disclosures of Statoil ASA should consequently be read with the Statoil group internal reorganisation of the net assets on the NCS in mind.

As a result of the Statoil group internal reorganisation, the nature of Statoil ASA's operations and transactions were changed so that its functional currency also changed from NOK to USD effective as of the same date and with prospective effect. The presentation currency for Statoil ASA however remains NOK.

2 Summary of significant accounting policies

Statement of compliance
The financial statements of Statoil ASA 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.

Reclassifications
Certain reclassifications have been made to prior year's figures to be consistent with current year's presentation.

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.

Jointly controlled assets
Interests in jointly controlled assets are recognised by including Statoil ASA's share of assets, liabilities, income and expenses on a line-by-line basis.

Statoil as operator of jointly controlled assets
Indirect operating expenses such as personnel expenses are accumulated in cost pools. These expenses are allocated to business areas and Statoil operated jointly controlled assets (licenses) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets reduce the expenses in the company's Statement of income. Only Statoil's share of Statement of income and balance sheet items related to Statoil operated jointly controlled assets are reflected in the Statement of income and Balance sheet.

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 (currencies other than Statoil ASA's functional currency, which from 1 January 2009 is USD) are translated to USD (NOK in 2008) at the foreign exchange rate at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to USD (NOK in 2008) 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.

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

Revenues from the production of oil from properties in which Statoil ASA has an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (sales method). Where Statoil ASA has lifted and sold more than the ownership interest, an accrual is recorded for the cost of the overlift. Where the company has lifted and sold less than the ownership interest, costs are deferred for the underlift.

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'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's and Statoil Petroleum AS' oil production are recorded 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 recorded as an equity transaction (included in additional paid-in capital).

Research and development
The company undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. The company's share of the licence holders funding and the total costs of the unfunded projects are development costs that 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; 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 recorded 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, 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 Norwegian continental shelf (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 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, 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 expenditures are incurred. Uplift benefit is recorded 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 derecognition or tested for impairment. Geological and geophysical costs and other exploration expenditures are expensed as incurred.

For exploration and evaluation asset acquisitions (farm-in arrangements) in which the company has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are reflected in the financial statements as and when the exploration and development work progresses. Exploration and evaluation asset dispositions (farm-out arrangements) are accounted for on a historical cost basis with no gain or loss recognition.

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 a major capital expenditure can be justified, 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 moreover are no concrete plans for future drilling in the license. 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 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 Construction in progress (Property, plant & equipment) at the time of sanctioning of the development project.

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.

Exchanges of assets are measured at the fair value of the asset given up unless the exchange transaction lacks commercial substance or 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 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 of production installations and field-dedicated transport systems for oil and gas is calculated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Depreciation of other assets and of transport systems used by several fields is calculated on the basis of their estimated useful lives, 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 the company has established separate depreciation categories for platforms, pipelines, and wells as a minimum.

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 and are depreciated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Capitalised acquisition costs of proved properties are depreciated using the unit of production method based on total proved reserves. Depreciation of other assets and transport systems used by several fields is calculated on the basis of their estimated useful lives, normally using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production (E&P) assets the company has established separate depreciation categories for platforms, pipelines, and wells as a minimum.

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 equipment and Financial liabilities, respectively. Assets under development for finance lease purposes, and for which the company carries substantially all the risk in the construction period, are recorded 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 recognised in the Statement of income 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. When an asset leased by a jointly controlled asset in which the company participates qualifies as a finance lease, the company reflects its proportionate share of the leased asset and related obligations in the balance sheet as Property, plant and equipment and Financial 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.

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 Consolidated statements of income in the period for which the capacity contractually is available to the company.

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.

Intangible assets relating to expenditure on the exploration for and evaluation of oil and natural gas resources are not amortised. Such an asset is subject to impairment testing when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount (or at least on an annual basis), and is 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.

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 intangible assets and 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. 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 the company's estimated value in use, which is determined using a discounted cash flow model. 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.

Financial assets
The company assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

For assets carried at amortised cost, if there is objective evidence that an impairment loss on loans and receivables has been incurred, the carrying amount of the asset is reduced. 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. After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, and any 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 financial expenses.

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. 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.

Net periodic pension cost is accumulated in cost pools and allocated to business areas and Statoil operated jointly controlled assets (licenses) 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 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. Following Statoil ASA's change in functional currency as of 1 January 2009, 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.

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.

Asset retirement obligations
Liabilities for decommissioning expenses are recognised when the company has an obligation 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 reasonable estimate of that liability can be made. The expenses are estimated based 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, on construction or installation. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations. At the time of the obligating event, a decommissioning liability is recognised and classified as Asset retirement obligations. 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 license periods are deemed to have indefinite lives and in consequence no asset retirement obligation has been recorded. For retail outlets, decommissioning provisions are estimated on a portfolio basis.

When a liability for decommissioning cost is recognised, a corresponding amount is recorded 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 or change in timing of the decommissioning is reflected as an adjustment to the provision and the corresponding Property, plant and equipment.

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, are 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 financial risks as:

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

Market risk management
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 contractual arrangements (derivatives) in order to manage the commodity price, foreign currency rate, and interest rate risk. Statoil ASA use 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 our governing policies. To manage the commodities price risk Statoil ASA enters into commodity based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

Derivatives associated with crude oil and petroleum 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, 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
Statoil ASA's operating results and cash flows are affected by price developments of its main products, oil and gas, in addition to 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.

The following currency risk sensitivities by end of 2009 have been calculated by assuming a 12% change in the foreign currency exchange rates. By end of 2008 and 2007 a 20% and a 10% change respectively, was assumed in the calculation.

As of 1 January 2009 Statoil ASA, due to an internal group reorganisation, changed functional currency from NOK to USD. This change has impacted the currency risk sensitivity when comparing 2009 with previous years.

(in NOK million)	USD	EUR	GBP	CAD	NOK	SEK	DKK
At 31 December 2009							
Net gains (losses) (12% sensitivity)	0	(765)	309	(309)	8,502	(68)	(32)
Net gains (losses) (-12% sensitivity)	0	765	(309)	309	(8,502)	68	32
At 31 December 2008							
Net gains (losses) (20% sensitivity)	(41,585)	(2,513)	(360)	(35)	0	387	123
Net gains (losses) (-20% sensitivity)	41,585	2,513	360	35	0	(387)	(123)

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 becomes more diversified than by only being able to use the US floating rate debt market.

Statoil ASA principally manages the entity's interest rates by converting 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 also includes a mandate to deviate from base policy and keep part of the long term debt in fixed interest rates.

For the interest rate risk sensitivity in a 1.5 percentage point change has been used in the calculation for 2009. For 2008 and 2007 a one percentage point change was assumed. A decline in the interest rates result 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 2009. When the interest rate decline 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 that would impact Statoil ASA's income statement are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2009		
Interest rate risk (1.5 percentage point sensitivity)	2,106	(2,476)
At 31 December 2008		
Interest rate risk (1 percentage point sensitivity)	1,017	(1,017)

Credit risk

Credit risk is the risk that Statoil ASA's customers or counterparties will cause the entity financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from 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
- Continuous monitoring and managing credit exposures

Prior to entering into transactions with new counterparties, the credit policy requires all counterparties to be formally identified, approved, and assigned internal credit ratings as well as exposure limits. Once established, all counterparties are re-assessed at a minimum annually and monitored continuously. 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 are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only investment grade international banks are accepted.

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 entity'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)	2009	2008
Counter-party rated:		
Investment grade, rated A or above	516	1,381
Other investment grade	0	225
Non investment grade or not rated	88	188
Total	604	1,794

As of 31 December 2009, collateral is received in cash to offset a certain portion of Statoil ASA's credit exposure.

Liquidity risk

Liquidity risk is the risk that Statoil ASA will not be able to meet obligations associated with financial liabilities when 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. Planned capital expenditures have been adjusted and Statoil has, and will continue, to implement initiatives to cut costs. In order to secure necessary financial flexibility, which includes meeting the group's financial obligations, Statoil maintains what is believed 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 on a monthly basis.

Statoil ASA's operating cash flows are significantly impacted by the volatility in the oil and gas prices; however, during 2009 the overall liquidity position remained strong and the policies for managing liquidity remained unchanged.

The main cash outflows are the annual dividend payment and tax payments six times per year. If liquid assets one month after tax and dividend payment dates are below defined policy level, new long-term funding will be considered.

For information about Statoil ASA's non-current financial liabilities, see note 19 Non-current financial 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 2011 till 2031.

Fair value measurement of derivative financial instruments

Statoil ASA recognises derivative financial instruments in the balance sheets 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 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.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net fair value
At 31 December 2009			
Foreign currency instruments	297	(855)	(558)
Interest rate instruments	0	(1,455)	(1,455)
Crude oil and refined products	306	(588)	(282)
Natural gas and electricity	160	(203)	(43)
Total	763	(3,101)	(2,338)
At 31 December 2008			
Foreign currency instruments	173	(13,565)	(13,392)
Crude oil and refined products	40	(5)	35
Natural gas and electricity	1,878	(2,308)	(430)
Total	2,091	(15,878)	(13,787)

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 that are not recognised in the balance sheet. These agreements had at 31 December 2009 a fair value of NOK 6.2 billion. By end of 2008 the fair value was NOK 12.1 billion.

When calculating the fair value of the derivative financial instruments Statoil ASA uses prices quoted in an active market for identical assets to the extent possible. When this is not available Statoil ASA uses inputs into the valuation techniques that are observable either directly or indirectly. The most frequently valuation techniques used by Statoil ASA for the derivative financial instruments are mark to market calculation or a net present value calculation of expected future cash flows.

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.

(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 2009				
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 price inputs other than quoted prices but are from observable market transactions (Level 2)	763	(1,443)	(1,658)	(2,338)
Fair value based on unobservable inputs (Level 3)	0	0	0	0
Total fair value	763	(1,443)	(1,658)	(2,338)
At 31 December 2008				
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 price inputs other than quoted prices but are from observable market transactions (Level 2)	2,091	0	(15,878)	(13,787)
Fair value based on unobservable inputs (Level 3)	0	0	0	0
Total fair value	2,091	0	(15,878)	(13,787)

The first level in the above table, 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 calculated based on observable prices on identical instruments. This category will in most cases only be relevant for exchange traded financial instruments.

The second level in the above table, Fair value based on price inputs other than quoted prices but are from observable market transactions, is used for fair values that are calculated for Statoil ASA's non-standardised contracts based on 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.

The third level in the above table, 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 Business developments

In 2008 Statoil ASA acquired certain oil and gas production assets, with a carrying amount of NOK 9.1 billion, and related deferred tax liabilities, with a carrying amount of NOK 4.0 billion, from the wholly owned subsidiary Statoil Petroleum AS. The aquired net assets were transferred at their carrying amounts. The same assets were transferred back to Statoil Petroleum AS effective 1 January 2009, as part of the reorganisation described in note 1 Organisation and basis of presentation. This transaction was accounted for as an equity transaction with no gain or loss recognition.

In 2008 Statoil ASA sold certain shares in subsidiaries to other entities, wholly owned, directly or indirectly by Statoil ASA. These shares were transferred at their carrying amounts.

5 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)	2009	2008
Norway	24,082	43,205
Europe	173,978	344,523
America	88,705	134,372
Other	26,429	37,393
Revenues	313,194	559,493

(in NOK million)	2009	2008
Revenues third party	252,624	464,860
Intercompany revenues	60,570	94,633
Revenues	313,194	559,493

6 Remuneration

(in NOK million, except average work-year)	2009	2008
Salaries*	14,595	14,516
Pension costs	3,119	2,550
Payroll tax	2,404	2,184
Other compensations	1,661	1,743
Total	21,779	20,993
Average number of work-years	17,050	16,525

*Salaries are exclusive of reimbursement from the The Norwegian Labour and Welfare Administration.

Management remuneration in 2009 (in NOK thousand)

Members of Corporate Executive Committee 1)	Base pay 2)	LTI 3)	Bonus 4)	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 5)	Estimated present value of pension obligation
Lund Helge (CEO)	6,495	1,890	1,500	338	19	10,242	485	19	504	10,746	3,950	21,254
Bjørnson Rune (Executive vice president (E.V.P.), Natural Gas)	2,507	600	540	221	20	3,888	0	25	25	3,913	767	18,668
Jacobsen Jon Arnt (E.V.P, Manufacturing & Marketing)	2,874	669	361	68	8	3,980	0	37	37	4,017	1,398	16,147
Mellbye Peter (E.V.P, International Exploration & Production)	3,787	813	731	205	20	5,556	9	31	40	5,596	1,339	37,287
Sætre Eldar (CFO)	2,927	713	712	162	31	4,545	178	25	203	4,748	870	25,595
Øvrum Margareth (E.V.P, Technology & New Energy)	2,771	694	624	55	13	4,157	0	48	48	4,205	902	25,243
Nes Helga (E.V.P, Staff functions & corporate services)	2,271	550	365	176	39	3,401	181	17	198	3,599	684	17,150
Michelsen Øystein (E.V.P, Exploration & Production Norway)	3,220	750	481	217	6	4,674	280	23	303	4,977	749	21,378
Myrebø Gunnar (E.V.P, Projects & Procurement)	2,419	575	324	45	5	3,368	299	11	310	3,678	732	21,463
Total	29,271	7,254	5,638	1,487	161	43,811	1,432	236	1,668	45,479	11,391	204,185

1) In addition to remuneration to the members of the Corporate Executive Committee, a final payment to former E.V.P, Staff functions & corporate services, Hilde Merete Aasheim, was made during 2009. The payment covered vacation pay and value of unused vacation days. Total remuneration for Mrs. Aasheim during 2009 was NOK 416 thousand.

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

3) Fixed long-term incentive (LTI) element. The LTI implies an obligation to invest the net amount in Statoil shares. A lock-in period of 3 years applies for the investment.

4) Bonus paid in 2009 is related to the period 1 October 2007 to 31 December 2008 due to the merger between Statoil and Hydro Oil and Gas effective from 1 October 2007.

5) Pension cost is calculated based on actuarial assumptions and pensionable salary at 31 December 2009 and will be recognised as pension cost in the Statement of income in 2010. Payroll tax is not included.

Board of directors remuneration in 2009 (in NOK thousand)

Members of the board	Position	Board remuneration	Audit committee	Compensation committee	Total remuneration
Rennemo Svein	Chair of the board	590	0	63	653
Arnstad Marit	Deputy chair	375	105	0	480
Skaugen Grace R	Board member	300	0	90	390
Grieg Elisabeth	Board member	300	0	63	363
Svaan Morten	Board member	300	105	0	405
Bjørndalen Kjell	Board member	300	0	56	356
Franklin Roy	Board member	462	145	0	607
Bakkerud Lill-Heidi	Board member	300	0	0	300
Stausholm Jakob (member since 02.07.2009)	Board member	150	55	0	205
Iversen Einar Arne (member since 17.06.2009)	Board member	162	0	0	162
Nilsen Geir (observer in the period 01.01.2009 - 17.06.2009)	Observer	138	0	0	138
Clausen Claus (member in the period 01.01.2009 - 17.06.2009)	Board member	138	0	0	138
Nielsen Kurt Anker (member in the period 01.01.2009 - 24.03.2009)	Board member	68	34	0	102
Fritsvold Ragnar Per (observer in the period 01.01.2009 - 17.6.2009)	Observer	138	0	0	138
Total		3,721	444	272	4,437

STATEMENT ON REMUNERATION AND OTHER EMPLOYMENT TERMS FOR STATOIL'S CORPORATE EXECUTIVE COMMITTEE

In accordance with the Norwegian Public Limited Liability Companies Act § 6-16 a), the board has the intention to present the following statement regarding remuneration of Statoil's corporate executive committee to the 2010 annual general meeting:

1. Remuneration policy and concept for the accounting year 2010

1.1 Policy and principles

The company's established remuneration principles and concepts will be continued in the accounting year 2010. The temporary adjustments that were decided in 2009, due to the altered economic situation, will not be pursued in 2010. These extraordinary measures regarding base salary and variable pay for 2009 were not intended as permanent changes in the company's remuneration concept and will not apply in 2010. However, payment of annual variable pay in 2010 for the accounting year 2009 will be based on these extraordinary adjustments ref. section 2 below.

Statoil's remuneration policy is strongly linked to the company's people policy and core values. Certain key principles have been adopted for the design of the company's remuneration concept. These principles pertain in general but they are applied differently for the different remuneration systems and job categories.

The remuneration concept is an integrated part of our values based performance framework and shall:

- reflect our 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 and
- 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 composition of the total reward reflect the national and international framework and business environment Statoil operates within.

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, 6-14, 6-16 a) and the board's rules of procedures last amended 31 July 2008.

The board of directors has 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 decides 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 pay arrangements
- Other benefits

Fixed remuneration

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

Base salary

The base salary shall be competitive in the markets where the company operates and shall reflect the individual's responsibility and performance. The evaluation of performance is based on fulfilment of certain pre-defined goals; refer to "Variable pay" below. The base salary is normally reviewed once a year.

Long Term Incentive (LTI)

Statoil will continue with the established long-term incentive system for a limited number of senior managers, including the members of the corporate executive committee.

The long-term incentive system is a fixed, monetary compensation calculated in per cent of the participant's base salary; ranging from 20-30% depending on the participant's position. The participant is obliged to buy Statoil shares in the market with the fixed LTI amount (after tax deduction) every year and to hold the shares for a lock-in period of three years.

The long-term incentive and the annual variable pay system constitute a remuneration concept which focuses both on short- and long-term goals and results. The long-term incentive contributes to strengthening of the common interests between the top management and the shareholders of Statoil.

Variable pay

The intention is to continue with the company's variable pay concept in 2010. Based on performance, the chief executive officer is entitled to an annual variable pay with a maximum potential of 50% of the fixed remuneration. The executive vice presidents have an equivalent variable pay scheme with a maximum potential of 40%.

In order to obtain an improved distribution of the annual variable pay budget and to underpin a drive towards an even stronger performance it is decided to adjust the pay out level for performance at target from 67% to 50% of the maximum potential.

Remuneration policies' effect on risk

The remuneration concept is an integrated part of our performance management system. An overarching principle is that there should be a close link between performance and remuneration.

Individual salary and annual variable pay review shall be based on the performance evaluation in our performance management system. However, the participation in the long-term incentive (LTI) scheme and the size of the annual LTI element are not directly based on performance but linked to the position level of the executive.

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; finance, operations, market, HSE, people and organisation. In each perspective, both longer term strategic objectives and shorter term targets on Key Performance Indicators (KPI) are set, as well as an agreed set of actions. Behaviour goals are based on the core values and leadership principles of Statoil 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 for instance reviewed against their strategic contribution, sustainability and significant changes in assumptions.

This balanced score-card approach with goals defined in both the delivery and behaviour dimension and a holistic performance evaluation should significantly reduce the risk that our remuneration policies are likely to have a material adverse effect.

In the performance contract of the chief executive officer and chief financial officer one out 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's general pension plan is a defined benefit arrangement with a pension level amounting to 66% of the pensionable salary provided at least 30 years service period. Pension from the National Insurance scheme is taken into account when the pension is estimated. The retirement age is generally 67 years, for offshore employees 65 years.

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.

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

Four of the executive vice presidents have individual pension terms according to a previous standard arrangement decided October 2006. These executives are entitled, under specific terms, 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's general pension plan, these executive vice presidents have the right to an extra period corresponding to half a year of extra membership for each year the person has served the company as an executive vice president.

One of the executive vice presidents is entitled, under specific terms, to a pension amounting to 66% of pensionable salary and a retirement age of 62. Another executive vice president is, under specific terms, entitled to a pension amounting 70% of pensionable salary and a pension age of 62.

The individual pension terms outlined above are results of commitments according to previous arrangements. The previous standard arrangement for the executive vice presidents, as described above, was terminated in 2007. Until a new standardised, competitive model appropriate for the company's needs is established, Statoil will apply a retirement age of 65 years and a pension level amounting to 66% for executive vice presidents. This arrangement applies for two of the executive vice presidents.

In addition to the pension benefits outlined above the executive vice presidents 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.

Severance pay arrangements

If the board of directors gives the chief executive officer notice of termination of employment, he shall be entitled to severance pay corresponding to 24 months of base salary. The severance pay shall be calculated as from the expiry of the notice period of six months. The same amount of severance pay shall also be paid if the parties agree that the employment should be discontinued and the chief executive officer gives notice pursuant to a written agreement with the board. These terms and conditions apply according to chief executive officer's employment contract of 7 March 2004.

Executive vice presidents are entitled to severance pay equivalent to six months salary, excluding term of notice of six months, when the resignation is at the request from the company. The same amount of severance pay shall also be paid 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 in which severance pay is payable, will be fully deducted. This relates to earnings from any employment or business activity where the executive vice president has active ownership.

One of the executive vice presidents is according to a previous agreement entitled to severance pay of 18 months, excluding term of notice of six months, provided the resignation is at the request of the company.

The entitlement to severance pay 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.

The chief executive officer's/executive vice president's own notice will as a general rule not release any severance pay.

Other benefits

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

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

2. Execution of the remuneration policy and principles in 2009
In accordance with the extraordinary adjustments that were decided in 2009, the base salary of the chief executive officer and the other members of the corporate executive committee remained unchanged in 2009 compared to 2008.

The pay out of annual variable pay in 2010 will reflect that it was decided to reduce the maximum pay potential by 50% for performance pay earned in 2009. Accordingly, the maximum pay potential of the chief executive officer's variable pay scheme was reduced from 50% to 25% in 2009 whereas the maximum pay potential for the executive vice presidents was reduced from 40% to 20% in 2009.

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.

7 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 338 million and NOK 307 million related to 2009 and 2008, respectively. For the 2010 program (granted in 2009) the estimated compensation expense is NOK 387 million. At 31 December 2009 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 762 million.

8 Auditors' remuneration

(in NOK million, excluding VAT)	2009	2008
Audit fees	19.8	25.0
Audit related fees	4.0	5.2
Other service fees	3.6	0.1
Total	27.4	30.3

In addition to the figures above, audit fees to Ernst & Young related to Statoil ASA-operated licences amount to NOK 2.1 and NOK 5.8 million for 2009 and 2008, respectively.

9 Research and development expenditures

Research and development expenditures were NOK 70 million and NOK 1,626 million in 2009 and 2008, respectively. Research and development expenditures are partly financed by partners of Statoil-operated licences. Statoil ASA's share of the expenditures has been recognised as expense in the Statement of income.

10 Financial items

(in NOK million)	For the year ended 31 December 2009	2008
Foreign exchange gains (losses) non-current financial liabilities	0	(11,252)
Foreign exchange gains (losses) derivative financial instruments	9,722	(25,001)
Foreign exchange gains (losses) taxes payable	(1,930)	-
Other foreign exchange gains (losses)	2,816	(2,066)
Net foreign exchange gains (losses)	10,608	(38,319)
Dividends received	28	166
Gains (losses) financial investments	459	1,923
Interest income group companies	2,538	3,956
Interest income and other financial income	1,668	4,405
Interest income and other financial items	4,693	10,450
Capitalised borrowing costs	0	511
Accretion expense asset retirement obligation	0	(1,269)
Interest expense to group companies	(1,579)	(2,520)
Interest expense non-current financial liabilities incl. derivatives	(2,078)	(1,560)
Interest expense current financial liabilites and other finance expenses	(1,834)	(603)
Interest and other finance expenses	(5,491)	(5,441)
Net financial items	9,810	(33,310)

Foreign exchange gains (losses) derivative financial instruments include fair value changes of currency derivatives related to liquidity and currency risk management. Weakening of the US dollar versus the NOK for the year ended 31 December 2009 resulted in fair value gains on these positions which are recognised in the Statement of income. Correspondingly, strengthening of the US dollar versus the NOK for the year ended 31 December 2008 resulted in fair value losses.

For comparison for other foreign exchange gains and losses in 2009 with 2008, one need to take into account that the parent company Statoil ASA changed its functional currency from NOK to US dollar effective from 1 January 2009. Further information in note 1 Organisation and basis for preparation.

11 Income taxes

Income tax expense

(in NOK million)	2009	2008
Current taxes payable	2,076	84,787
Change in deferred tax	5,956	(5,478)
Income tax expense	8,032	79,309
Uplift credit for the year	0	7,461

Revenue from oil and gas activities on the NCS is taxed according to the Petroleum tax law. In addition to normal corporation tax, a petroleum surtax of 50% is levied after deducting uplift, an investment tax credit. With effect from 1 January 2009, the petroleum surtax is no longer levied, and Statoil ASA is only liable to the statutory tax rate. This change is caused by the transfer of net assets on the NCS to Statoil Petroleum AS.

Reconciliation of Norwegian nominal statutory tax rate to effective tax rate

(in NOK million)	2009	2008
Income before tax	36,909	119,946
Nominal tax rate 28%	10,335	33,585
Tax effect of:		
Petroleum surtax	0	52,668
Permanent differences caused by USD as functional currency	6,232	0
Other permanent differences	(8,552)	(7,007)
Income tax prior years	(190)	0
Other	207	63
Total	8,032	79,309
Effective tax rate (%)	21.76	66.12

Significant components of deferred tax assets and liabilities were as follow

	At 31 December	
(in NOK million)	2009	2008
Deferred tax assets on		
Inventory	88	948
Other current items	696	3,778
Pensions	4,177	9,158
Decommissioning and asset retirement obligations	0	18,702
Property, plant and equipment	278	0
Other non-current items	28	3,940
Total deferred tax assets	5,267	36,526
Deferred tax liabilities on		
Property, plant and equipment	0	57,790
Capitalised exploration expenditures and interest	0	12,125
Other non-current items	2,545	1,553
Total deferred tax liabilities	2,545	71,468
Net deferred tax (assets) / liabilities	(2,722)	34,942

At 31 December 2009, Statoil ASA had recognised net deferred tax assets of NOK 2.7 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)	2009	2008
Deferred income tax (assets) / liabilities at 1 January	34,942	34,921
Charged to the Statement of income	5,956	(5,478)
Change in deferred tax from transfer of assets to/from Statoil Petroleum AS	(44,252)	3,970
Acquisitions, sales and other	632	1,529
Deferred income tax (assets) / liabilities at 31 December	(2,722)	34,942

12 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 2008	3,136	327,340	4,991	990	4,276	24,529	365,262
Transfers to Statoil Petroleum AS - original cost	(842)	(327,324)	(3,749)	(72)	0	(24,442)	(356,429)
Additions and transfers	631	0	0	264	1	0	896
Disposals assets at cost	(262)	0	(29)	(2)	0	0	(293)
Effect of movements in foreign exchange - assets	(389)	(16)	(264)	(173)	(744)	(20)	(1,606)
Cost at 31 December 2009	2,274	0	949	1,007	3,533	67	7,830
Accumulated depr. and impairment losses at 31 December 2008	(2,062)	(222,560)	(3,485)	(232)	(611)	0	(228,950)
Transfers to Statoil Petroleum AS - depreciation	735	222,547	2,545	2	0	0	225,829
Depreciation and amortisation	(496)	0	(42)	(41)	(190)	0	(769)
Net impairment losses	0	0	(44)	0	0	0	(44)
Accumulated depreciation and impairment disposed assets	256	0	17	0	0	0	273
Effect of movements in foreign exchange - depreciation and impairment losses	266	13	174	30	119	0	602
Accumulated depr. and impairment losses at 31 December 2009	(1,301)	0	(835)	(241)	(682)	0	(3,059)
Carrying amount at 31 December 2009	973	0	114	766	2,851	67	4,771
Estimated useful lives (years)	3 - 10		15-20	20 - 33	20 - 25		

The book value of vessels consists of financial leases.

13 Investments in subsidiaries and associated companies

(in NOK million)	Subsidiaries	Associates
Investment at 1 January 2009	281,045	1,040
Net income subsidiaries and associated companies	28,302	129
Additional paid-in equity	(144)	892
Pension adjustement	(88)	0
Distributions	(15,296)	(1,302)
Translation adjustments	(36,185)	(154)
Investment at 31 December 2009	257,634	605

Negative paid-in equity is due to a group contribution from Statoil Petroleum AS to Statoil ASA of NOK 30 billion for 2009.

Ownership in certain subsidiaries (in %)

Name	%	Country of incorporation	Name	%	Country of incorporation
SIA Statoil Latvija	100	Lativia	Statoil Norge AS	100	Norway
Statholding AS	100	Norway	Statoil Norsk LNG AS	100	Norway
Statoil AB	100	Sweden	Statoil North Africa Gas AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil North America Inc.	100	United States
Statoil Angola Block 17 AS	100	Norway	Statoil Orient AG	100	Switzerland
Statoil Angola Block 31 AS	100	Norway	Statoil Petroleum AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil Polen Invest AS	100	Norway
Statoil Azerbaijan AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil BTC Finance AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Coordination Centre NV	100	Belgium	Statoil 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 Exploration Ireland Ltd.	100	Ireland	Statpet Invest AS	100	Norway
Statoil Forsikring AS	100	Norway	UAB Lietuva Statoil	100	Lithuania
Statoil Hassi Mouina AS	100	Norway			
Statoil New Energy AS	100	Norway	Statoil Methanol ANS	82	Norway
Statoil Nigeria AS	100	Norway	Mongstad Refining DA	79	Norway
Statoil Nigeria Deep Water AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Nigeria Outer Shelf AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway

Ownership in certain associated companies (in %)

Name	%	Country of incorporation
Naturkraft AS	50	Norway
Nova Naturgass AB	30	Sweden
Vestprosess DA	34	Norway

14 Financial assets

Non-current financial assets

(in NOK million)	At 31 December 2009	2008
Financial investments	11	17
Financial receivables	1,285	557
Financial assets	1,296	574

Of the Financial receivables at 31 December 2009 a balance of NOK 0.8 billion relates to the Naturkraft financing project, and NOK 0.3 billion relate to long-term prepayments. Correspondingly NOK 0.6 billion were long-term prepayments at 31 December 2008.

Non-current receivables on subsidiaries

(in NOK million)	At 31 December 2009	2008
Interest bearing receivables on subsidiaries	40,866	41,050
Non-interest bearing receivables on subsidiaries	6,785	3,138
Receivables on subsidiaries	47,651	44,188

Interest bearing receivables on subsidiaries at 31 December 2009 are due in more than five years. Non-interest bearing receivables on subsidiaries at 31 December 2009 and 2008 mainly relate to pension, see note 20 Pension liabilities.

Current financial investments

(in NOK million)	At 31 December 2009	2008
Money market funds	1,905	2,616
Financial investments	1,905	2,616

Current financial investments at 31 December 2009 and 2008 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 2009 and 2008 was NOK 1.6 billion and NOK 2.4 billion, respectively.

15 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 2009	2008
Crude oil	9,505	5,317
Petroleum products	2,316	1,316
Other	155	187
Inventories	11,976	6,820

A write-down of inventory to net realisable value has been recognised as an expense in 2009. The write-down was insignificant at year end 2009 and amounted to NOK 2.8 billion at year end 2008.

16 Trade and other receivables

(in NOK million)	At 31 December 2009	2008
Trade receivables	30,127	30,693
Other receivables	1,926	13,762
Trade and other receivables	32,053	44,455

Other receivables in 2008 consists mainly of receivables towards joint ventures, associated companies and other related parties.

17 Cash and cash equivalents

(in NOK million)	At 31 December 2009	2008
Cash at bank	123	707
Time deposits and collateral deposits	14,337	5,565
Cash and cash equivalents	14,460	6,272

Cash and cash equivalents at 31 December 2009 include restricted cash of NOK 1.3 billion related to trading activities, correspondingly restricted cash at 31 December 2008 was NOK 3.2 billion. This restricted cash is related to certain collateral requirements set out by exchanges where the company is participating. The terms and conditions related to these requirements are determined by the respective exchanges.

For reconciliation of Cash and cash equivalents reported in the Balance sheet, see Statement of cash flows.

18 Equity and shareholders

Change in equity

(in NOK million)	2009	2008
Shareholders' equity 1 January	182,466	143,724
Net income	28,878	40,637
Actuarial gain employee retirement benefit plans	2,432	(9,535)
Foreign currency translation adjustments	(20,072)	30,880
Ordinary dividend	(19,100)	(23,090)
Merger related adjustments	251	0
Value of stock compensation plan	282	80
Treasury shares purchased	(267)	(230)
Total equity 31 December	174,870	182,466

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	6,028,607	2.50	15,071,517.50
Total outstanding shares	3,182,618,496	2.50	7,956,546,240.00

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 15 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 2009 (in %)		
1	THE NORWEGIAN STATE (Ministry of Petroleum and Energy)	67.00
2	FOLKETRYGDFONDET (Norwegian national insurance fund)	3.26
3	BANK OF NEW YORK, ADR DEPARTEMENT*	1.92
4	STATE STREET BANK*	1.36
5	CLEARSTREAM BANKING S.A.*	1.33
6	JP MORGAN CHASE BANK*	1.25
7	STATE STREET BANK*	1.09
8	STATE STREET BANK*	0.79
9	BANK OF NEW YORK MELLON*	0.79
10	THE NORTHERN TRUST	0.69
11	JP MORGAN CHASE BANK*	0.53
12	DNB NOR BANK ASA	0.48
13	THE NORTHERN TRUST	0.47
14	STATE STREET BANK*	0.43
15	THE NORTHERN TRUST	0.37
16	BANK OF NEW YORK MELLON*	0.36
17	STATE STREET BANK*	0.36
18	SKANDINAVISKA ENSKILDA BANK	0.35
19	BANK OF NEW YORK MELLON*	0.34
20	RBC DEXIA INVESTORS	0.34

* Client account and similar

Members of the board of directors, corporate executive committee and corporate assembly holding shares as of 31 December 2009:

Board of directors	
Svein Rennemo	10,000
Marit Arnstad	0
Elisabeth Grieg	33,108
Kjell Bjørndalen	0
Grace Reksten Skaugen	400
Jakob Stausholm	0
Roy Franklin	0
Lill-Heidi Bakkerud	330
Morten Svaan	1,245
Einar Arne Iversen	2,561

Corporate executive committee	
Helge Lund (Chief Executive Officer)	23,515
Eldar Sætre	9,644
Margareth Øvrum	12,031
Rune Bjørnson	7,853
Jon Arnt Jacobsen	10,982
Peter Mellbye	12,170
Øystein Michelsen	5,866
Gunnar Myrebøe	5,595
Helga Nes	3,616

Corporate assembly (in total)	5,841

19 Non-current financial liabilities

(in NOK million)	At 31 December 2009	2008
Unsecured bonds	74,830	40,548
Unsecured loans	4,873	6,104
Financial lease obligation	3,114	3,932
Gross financial liabilities	82,817	50,584
Less current portion	2,688	5,633
Financial liabilities	80,129	44,951
Weighted average interest rate (%)	5.19	5.97

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 11 March 2009 Statoil ASA executed the issuance of a GBP 0.8 billion bond maturing in March 2031, a EUR 1.2 billion bond maturing in March 2021 and a EUR 1.3 billion bond maturing in March 2015. All bonds were issued under Statoil ASA's Euro Medium Term Note Programme and have been listed on the London Stock Exchange.

On 23 April 2009 Statoil ASA executed the issuance of a USD 0.5 billion bond maturing in April 2014 and a USD 1.5 billion bond maturing in April 2019. These registered bonds were issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the SEC in the United States.

On 15 October 2009 Statoil ASA executed the issuance of a USD 0.9 billion bond maturing in October 2014. The registered bond was issued under the Registration Statement on Form F-3 ("Shelf Registration") filed with the SEC in the United States.

Non-current financial liabilities include financial lease obligations. More information is given in note 24 Leases.

Details of largest unsecured bonds

Bond agreement	Fixed interest rate	Issued (year)	Maturity (year)	Carrying amount in NOK million at 31 December 2009	2008
USD 1500 million	5.250%	2009	2019	8,613	-
USD 900 million	2.900%	2009	2014	5,174	-
USD 500 million	3.875%	2009	2014	2,870	-
USD 500 million	5.125%	2004	2014	2,887	3,498
USD 500 million	6.500%	1998	2028	2,859	3,462
USD 481 million	7.250%	2000	2027	2,776	3,363
USD 300 million	7.750%	1993	2023	1,733	2,100
EUR 1300 million	4.375%	2009	2015	10,782	-
EUR 1200 million	5.625%	2009	2021	9,887	-
EUR 500 million	5.125%	1999	2011	4,148	4,915
EUR 300 million	6.250%	1999	2010	2,494	2,960
GBP 800 million	6.875%	2009	2031	7,421	-
GBP 225 million	6.125%	1998	2028	2,096	2,277

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's secured bankloans in USD have been secured by mortgage in shares in a subsidiary and investments in other companies with a combined book value of NOK 2.3 billion, and the group's pro-rata share of income from certain applicable projects.

Statoil has 27 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 agreements' carrying value is NOK 75.9 billion at 31 December 2009 closing rate.

Non-current financial liabilities repayment profile

(in NOK million)	
2011	2,748
2012	3,181
2013	2,696
2014	6,518
Thereafter	64,986
Total	80,129

Statoil ASA has an agreement with an international bank syndicate for committed non-current revolving credit facility totalling USD 2.0 billion, all undrawn at the 31 December 2009.

20 Pension liabilities

Pension obligation

Statoil ASA (Statoil in following text) is obligated to follow the Act on Mandatory company pensions. The company's pension scheme follows the requirement as included in the Act.

Statoil recognises actuarial gains and losses directly in retain earnings, outside the Statement of 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.

Statoil has defined benefit retirement plans which cover all of its employees. Plan benefits are generally based on years of service and final salary level. 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.

Statoil is - due to National agreements - a member of the "agreement-based early retirement plan" (AFP). The members pay an annual fee per active employee. This part of the plan is defined as a multi-employer plan. The administrator of this plan is not able to calculate the members' share of assets and liabilities and this plan is consequently accounted for as a defined contribution plan. In addition the members have an obligation to pay a percentage of the benefits when an employee retires through AFP. This obligation is a defined benefit plan. When an employee retires through AFP, Statoil also offers a gratuity. This is also a defined benefit plan, and included in the provision related to the defined benefit plans.

A new legislation on the AFP was passed by the Norwegian Parliament 19 February 2010. This law is one part of the Norwegian pension and insurance reform effective from 1 January 2011. Several new laws affecting Norwegian pension and insurance schemes will be passed during 2010. Together with the revised national state pension and insurance legislation this forthcoming legislation will establish a new framework for private sector pension schemes in Norway which requires review and adapation of existing schemes. Statoil will undertake a review of the total pension scheme during 2010 as a basis for deciding a revised model based on the new legislation.

The obligations related to the defined benefit plans were measured at 31 December, 2009 and 2008. 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 have been tested against historical observations. At 31 December 2009 the discount rate for the defined benefit plans in Norway was estimated to be 4.75% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 20 year yield curve to match Statoil's payment portfolio for earned benefits.

Social security tax is calculated based on the pension plan's net unfunded status. Social security tax is included in the projected benefit obligation.

Statoil has more than one defined benefit plan but the note is made in total since the plans are not subject to materially different risks.

Net periodic pension cost

(in NOK million)	2009	2008
Current service cost	2,644	2,248
Interest cost on prior years' benefit obligation	2,418	2,320
Expected return on plan assets	(1,770)	(1,948)
Amortisation of actuarial gain or loss related to termination benefits	(242)	(215)
Losses (gains) from curtailment or settlement	0	73
Defined benefit plans	3,050	2,478
Multi-employer plans	69	72
Total net pension cost	3,119	2,550

Pension cost includes social security tax.

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

Change in projected benefit obligation (PBO)

(in NOK million)	2009	2008
Projected benefit obligation at 1 January	54,122	46,993
Current service cost	2,644	2,248
Interest cost on prior years' benefit obligation	2,418	2,320
Actuarial loss (gain)	(1.448)	3,575
Benefits paid	(1,412)	(1,195)
Settlements/curtailments	0	132
Change in receivable on subsidiary related to termination benefits	(3,846)	49
Other changes	(222)	0
Projected benefit obligation at 31 December	52,256	54,122

Change in pension plan assets

(in NOK million)	2009	2008
Fair value of plan assets at 1 January	31,231	32,124
Expected return on plan assets	1,770	1,948
Actuarial gain (loss)	2,662	(3,791)
Company contributions (including social security tax)	4,805	1,200
Benefits paid	(314)	(274)
Settlements	0	24
Fair value of plan assets at 31 December	40,154	31,231

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 table Actuarial gains and losses recognised directly in retained earnings below.

Total provision for pensions

(in NOK million)	2009	2008
Balance sheet provision at 1 January	(22,891)	(14,869)
Net periodic pension costs defined benefit plans	(3,050)	(2,478)
Net actuarial loss (gain) recognised in retain earnings	3,868	(7,582)
Less employer contributions/benefit paid during year	4,805	1,200
Less benefit paid during year	1,098	921
Change in receivable on subsidiary related to termination benefits	3,846	(49)
Other changes	223	(34)
Balance sheet provision at 31 December	(12,101)	(22,891)

Surplus (deficit) at 31 December

(in NOK million)	2009	2008	2007
Surplus (deficit) at 31 December	(12,101)	(22,891)	(14,869)
Represented by:			
Asset recognised as Non-current pension asset	2,665	0	1,561
Asset recognised as Non-current receivables from subsidiaries*	5,916	2,070	2,117
Liability recognised as Non-current pension liability	(20,682)	(24,961)	(18,384)
Liability recognised as Current liability	0	0	(163)

Projected benefit obligation specified by funded and unfunded plans

(in NOK million)	2009	2008
Funded pension plans	(37,489)	(34,236)
Unfunded pension plans	(14,767)	(19,886)
PBO at 31 December	(52,256)	(54,122)

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

Actuarial gains and losses recognised directly in retained earnings

(in NOK million)	2009	2008
Unrecognised actuarial losses (gains) at 1 January	0	0
Actuarial losses (gains) on plan assets occur during the year	(2,662)	3,791
Actuarial losses (gains) on benefit obligation occur during the year	(1,448)	3,575
Actuarial losses (gains) related to currency effects on net obligation *	3,867	0
Recognised in the income statement during the year	242	215
Foreign exchange translation *	(3,064)	0
Recognised directly in retained earnings during the year	3,065	(7,581)
Unrecognised actuarial losses (gains) at 31 December	0	0

*In the table Actuarial gains and losses recognised directely in retained earnings, Actuarial losses (gains) related to currency effects on net obligation refer to translation of the net obligation in NOK to the functional currency US dollar. The line Foreign exchange translation refer to translation from functional currency US dollar to presentation currency NOK. Statoil ASA changed its functional currency as of 1 january 2009, for further information see note 1 Organisation and note 2 Significant accounting policies.

Actual return on plan assets

(in NOK million)	2009	2008
Actual return on plan assets	4,432	(1,843)

History of experience gains and losses

(in NOK million)	2009
Fair value of plan assets at 31 December	40,154
Projected benefit obligation included receivable related to termination benefits	52,256
Receivable on subsidiary related to termination benefits	5,916
Projected benefit obligation at 31 December	58,172
Difference between the expected and actual return on plan assets	
a) Amount	(2,662)
b) Percentage of plan assets	(6.63%)
Experience (gains)/losses on plan liabilities	
a) Amount	(1,923)
Percentage of present value of plan liabilities	(3.31%)

In 2009 the cumulative amount of actuarial gains and losses recognised directly to equity amounted to NOK 10.3 billion after tax (negative effect on equity). NOK 10.3 billion is related to actuarial gains and losses recognised in Statoil ASA and an insignificant amount is related to subsidiaries accounted for using the equity method. In 2008 the cumulative amount of actuarial gains and losses recognised directly to equity amounted to NOK 13.3 billion after tax (negative effect on equity). NOK 12.6 billion is related to actuarial gains and losses recognised in Statoil and 0.7 billion is related to subsidiaries accounted for using the equity method.

Weighted-average assumptions for the year (Profit and Loss items)

in %	2009	2008
Discount rate	4.50	5.00
Expected return on plan assets	5.75	6.25
Rate of compensation increase	4.00	4.50
Expected rate of pension increase	2.75	3.25
Expected increase of social security base amount (G-amount)	3.75	4.25
Expected inflation	2.00	2.25

Weighted-average assumptions at end of year (Balance sheet items)

in %	2009	2008
Discount rate	4.75	4.50
Expected return on plan assets	6.00	5.75
Rate of compensation increase	4.25	4.00
Expected rate of pension increase	3.00	2.75
Expected increase of social security base amount (G-amount)	4.00	3.75
Expected inflation	2.25	2,00
Average remaining service period in years	15	15

Expected attrition at 31 December 2009 was 2.0%, 2.0%, 1.5%, 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. Expected attrition at 31 December 2008 was 2.0%, 2.0%, 1.5%, 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.

Expected utilisation of Agreement-based early retirement pension (AFP) is 50% for employees at 62 years and 30% for the remaining employees at 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), hence reducing the mortality rate with a a minimum, of 15 % for male and 10% for female for each employee is used as the best mortality estimate. The disability table, KU, developed by the insurance company Storebrand, aligns with the actual disability risk for Statoil.

Below is shown a selection related to demographic assumptions used at 31 December 2009. The table shows the probability of disability or death, 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 shows 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 2009. 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)	0.25%	-0.25%	0.25%	-0.25%	0.25%	-0.25%	0.25%	-0.25%
Changes in:								
Projected benefit obligation at 31 December 2009	(2.01)	2.15	0.88	(0.89)	(1.81)	2.00	0.97	(0.92)
Service cost 2010	(0.14)	0.15	0.06	(0.06)	(0.13)	0.14	0.06	(0.06)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2009 and 2008. 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 included markup for estimating a longer interest rate than 10 year) is applied as a starting point for calculation of return on plan assets. The return in the money market is calculated by taking a deduction on bond yield. Based on historical data, equities and real estate are expected to give a long-term additional return above money market.

In its asset management, the pension fund 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. The pension fund's target returns require a need to invest in assets with a higher risk than risk-free investments. Risk is reduced through maintaining a well diversified asset portfolio. Assets are diversified both in terms of location and different asset classes. Derivatives are used within set limits to facilitate effective asset management.

Pension assets allocated on respective investments classes

(in %)	2009	2008
Equity securities	39.60	19.10
Bonds	39.40	70.20
Commercial papers	14.70	3.30
Real estate	5.10	6.90
Other assets	1.20	0.50
Total	100.00	100.00

Properties owned by Statoil pension fund amounted to NOK 2.1 billion and NOK 2.2 billion of total pension assets at 31 December 2009 and 2008, respectively, and are rented to Statoil companies.

Statoil's pension fund invests in both financial assets and real estate. The expected rate of return on real estate is expected to be between the rate of return on equity securities and debt securities. The table below presents the portfolio weight and expected rate of return of the finance portfolio, as approved by the board of the Statoil pension funds for 2010. 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	59.50	(+/- 5)	X
Commercial papers	0.50	(+15/-0.5)	X - 0.4
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.

Contribution to pension plans may either be paid in cash or be deducted from the pension premium fund. The pension premium fund amounted to NOK 7.2 billion and 4.5 billion at 31 December 2009 and 2008, respectively. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. In 2009 a pension premium amounting to NOK 4.1 billion was paid to the premium fund. In addition Statoil intends to pay to the pension premium fond approximately NOK 3.3 billion late March 2010. In 2008, NOK 2.9 billion was deducted from the pension premium fund. NOK 1.2 billion was paid to Statoil pension fund as a capital increase in 2008.

The expected company contribution related to 2010 amounts to NOK 2.1 billion.

21 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	2009	2008
Asset retirement obligations at 1 January	24,068	22,723
Liabilities incurred/revision in estimates	0	722
Accretion	0	1,269
Disposals	0	(412)
Transfer of licenses to Statoil Petroleum AS*	(24,068)	0
Incurred removal cost	0	(234)
Asset retirement obligations at 31 December	0	24,068
Current portion of asset retirement obligations	0	286
Analysis of provisions and other liabilities at 31 December		
Non-current portion of asset retirement obligations	0	23,782
Other provisions and other liabilities	1,322	2,468
Asset retirement obligations, other provisions and other liabilities	1,322	26,250

22 Trade and other payables

(in NOK million)	At 31 December 2009	2008
Trade payables	10,501	8,497
Non-trade payables	5,824	16,174
Payables to associated companies and other related parties	9,141	8,970
Trade and other payables	25,466	33,641

23 Current financial liabilities

(in NOK million)	At 31 December 2009	2008
Bank loans and overdraft facilities	44	39
Collateral liabilities	4,654	10,123
Commercial paper liabilities	0	2,989
Current portion of non-current loans	2,494	5,398
Current portion of financial lease obligations	194	235
Other financial liabilities	0	255
Financial liabilities	7,386	19,039
Weighted average interest rate (%)	2.04	2.38

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

Commercial paper liabilities relate to the US Commercial Paper (CP) program available for short-term funding. Statoil currently has a CP program totalling USD 4 billion, all undrawn at 31 December 2009.

As of 31 December 2009 and 2008, Statoil had no committed short-term credit facilities available or drawn.

24 Leases

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

As a member of the Snøhvit Sellers' group Statoil ASA has entered into leasing arrangements for three LNG vessels on behalf of Statoil ASA and the SDFI (the State's direct financial interest). 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 2009, net rental expense was NOK 1.3 billion (NOK 7.1 billion in 2008) of which minimum lease payments were NOK 1.3 billion (NOK 8.7 billion in 2008), and sublease payments received were NOK 55 million (NOK 1.6 billion in 2008). Contingent rents expensed were immaterial both years.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2009.

Amounts related to finance leases include future minimum lease payments for assets recognised in the financial statements at year-end 2009.

(in NOK million)	Operating leases	Operating sublease	Financial lease: Minimum lease payments	Financial lease: Interest	Financial lease: Net present value minimum lease payments
2010	1,210	(133)	304	(25)	279
2011	877	(118)	304	(38)	266
2012	476	(118)	304	(50)	254
2013	247	(118)	304	(60)	244
2014	224	(118)	304	(70)	234
Thereafter	506	(878)	2,938	(1,101)	1,837
Total future minimum lease payments	3,540	(1,483)	4,458	(1,344)	3,114

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2009 and 2008.

(in NOK million)	2009	2008
Vessels and equipment	3,530	4,276
Accumulated depreciation	(679)	(611)
Capitalised amount	2,851	3,665

25 Other commitments and contingencies

Long-term commitments

Statoil ASA has entered into various long-term agreements for pipeline transportation as well as terminal, processing, storage and entry capacity commitments and commitments related to specific purchase agreements. The agreements ensure the rights to the capacity or volumes in question, but also impose an obligation to pay for the agreed-upon service or commodity, irrespectively of actual use. The following table outlines nominal minimum obligations for future years.

Statoil ASA has entered into a number of general or field specific long-term frame agreements mainly related to crude oil loading and transport capacity availability. The main contracts run up until the end of the respective field lives. Such contracts have not been included in the below table of contractual commitments unless they entail specific minimum payment obligations.

Obligations payable by Statoil ASA to entities accounted for using the equity method are included gross in the tables below. As regards assets (e.g. pipelines) that the company accounts for by including 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 (gross commitment less Statoil's ownership share).

Nominal minimum commitments at 31 December 2009:

(in NOK million)	
2010	4,807
2011	4,596
2012	4,022
2013	3,875
2014	2,929
Thereafter	18,167
Total	38,396

Guarantees
The company has provided parent company guarantees covering liabilities of subsidiaries with operations in Algeria, Angola, Belgium, Brazil, Canada, Cuba, Germany, Great Britain, India, Iran, Ireland, Libya, Mozambique, the Netherlands, Russia, Sweden, the Faroe Islands, USA and Venezuela. The company has also counter-guaranteed certain bank guarantees covering liabilities of subsidiaries in Angola, Belgium, Brazil, Canada, Cuba, Egypt, Great Britain, Indonesia, Italy, the Netherlands, Nigeria, Norway, USA and Venezuela. The company has further provided a guarantee covering its pro-rata share of the liabilities of a 50% owned company with operations in Great Britain.

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 3.8 billion with terms extending until 2050. 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 financial statements at year end 2009.

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 13 Investments in subsidiaries and associated companies.

Statoil ASA issued a declaration to the Norwegian Ministry of Petroleum and Energy (MPE) in 1999 in connection with a dispute between four Åsgard partners and Statoil related to the construction of new facilities for the Åsgard development at the Kårstø Terminal. The declaration confirmed that the MPE will receive similar treatment as the four Åsgard partners with respect to the disputed issues. As of 1 January 2009 and following the group internal reorganisation of the NCS assets, the Statoil group's activity and assets related to this declaration belong to Statoil Petroleum AS. On the basis of the declaration, the MPE alleged the right to compensation and initiated legal proceedings against Statoil on 29 April 2008 in a writ involving a multi-component claim. The aggregate principal exposure for the claim is estimated to be between NOK 4 and 7 billion after tax. Following a verdict in Stavanger district court on 15 January 2010, Statoil and the MPE on 5 March 2010 reached an amicable settlement of the case in which both parties waived their rights to appeal the court verdict. Under the settlement Statoil agreed to pay the MPE a cash compensation of NOK 500 million after tax, and NOK 375 million in pre-tax interest, corresponding to NOK 270 million after tax.

During the fourth quarter of 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. The dispute with ExxonMobil was settled in October 2009. The impact of this settlement on the financial statements was not material.

Statoil was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to Statoil as of 1 October 2007 as part of the merger with Hydro Petroleum, and which could be in conflict with applicable Norwegian and US anti-corruption legislation. Following a preliminary assessment by Statoil, an external review of the relevant aspects was initiated. The external US and Norwegian legal counsels that have conducted the review delivered their report to Statoil ASA's CEO on 6 October 2008. The report has also been delivered to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), the US Department of Justice, the US Securities and Exchange Commission and Libyan authorities. The report does not draw any legal conclusions. In accordance with the mandate for the review, the report entails the facts relevant to applicable Norwegian and US anti-corruption legislation to which Statoil ASA may be subject as a result of the merger. Økokrim informed on 15 May 2009 that there will be no investigation related to the international activities of former Hydro Oil & Energy. Neither US authorities nor Libyan authorities have as of today initiated any steps in relation to the matters described in the investigation reports.

During the normal course of its business Statoil is involved in legal proceedings, and several other unresolved claims are currently outstanding. The ultimate liability or asset in respect of such litigation and claims cannot be determined at this time. Statoil has provided in its financial statements for probable liabilities related to litigation and claims based on the company's best judgement. Statoil does not expect that the financial position, results of operations or cash flows will be materially affected by the resolution of these legal proceedings.

26 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 arms-length terms.

The ownership interests of the Norwegian State in Statoil ASA are administrated by the Norwegian Ministry of Petroleum and Energy (MPE). The following transactions with SDFI volumes were made between Statoil ASA and MPE for the years presented:

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 74,338 million (204 million barrels oil equivalents), NOK 112,682 million (223 million barrels oil equivalents) and NOK 98,498 (237 million barrels oil equivalents) in 2009, 2008 and 2007, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licences) amounted to NOK 265 million, NOK 375 million and NOK 287 million in 2009, 2008 and 2007, respectively. Payables to associated companies and other related parties in note 22 Trade and other payables, are amounts payable to the Norwegian State for these purchases.

The State's natural gas production, which Statoil ASA is selling, in its own name, but for the Norwegian State's account and risk as well as related expenditures refunded by the State, are presented at net value in the financial statement of Statoil ASA.

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 unconsolidated affiliated entities. Such transactions are carried out at arms-length terms, and are included within the applicable captions in the statements of income.

27 Subsequent events

Statoil's board of directors has approved a proposal to create a stand-alone Energy & Retail (E&R) business through an initial public offering (IPO) on the Oslo Stock Exchange. The IPO will take place at the earliest in the fourth quarter of 2010 or at a time when the capital market is deemed favourable for such an offering.

Statoil intends to remain a majority shareholder of E&R at the time of the initial public offering and listing. The size and time horizon of Statoil's future ownership in E&R will be tailored to support and develop company value both for E&R and for the Statoil Group.

Stavanger, 17 March 2010

THE BOARD OF DIRECTORS OF STATOIL ASA

SVEIN RENNEMO
CHAIR

MARIT ARNSTAD
DEPUTY CHAIR

LILL-HEIDI BAKKERUD

KJELL BJØRNDALEN

ROY FRANKLIN

ELISABETH GRIEG

EINAR ARNE IVERSEN

GRACE REKSTEN SKAUGEN

JAKOB STAUSHOLM

MORTEN SVAAN

HELGE LUND
PRESIDENT AND CEO

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

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Statoil ASA

We have audited the accompanying consolidated balance sheets of Statoil ASA as of 31 December 2009, 2008 and 1 January 2008, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended 31 December 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Statoil ASA at 31 December 2009, 2008 and 1 January 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended 31 December 2009, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

As discussed in Note 8.1.2, Significant changes in accounting policies, to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Statoil ASA's internal control over financial reporting as of 31 December 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated 17 March 2010 expressed an unqualified opinion thereon.

Ernst & Young AS
Stavanger, Norway
17 March 2010

Note: The translation to English has been prepared for information purposes only.

HSE accounting

Statoil's objective is to operate with zero harm to people and the environment and in accordance with principles for sustainable development. We support the Kyoto Protocol and apply the precautionary principle in the conduct of our business.

Our HSE management system is an integrated part of our total management system, and it is described in our governing documents.

A key element in our HSE management system is recording, reporting and assessing relevant data. HSE performance indicators have been established to provide information about historical trends. The intention is to document quantitative developments over time and use the information in decision-making and for systematic and purposeful improvement efforts.

The HSE data are compiled by the business units and reported to the corporate executive committee, which evaluates trends and decides whether improvement measures are required. The chief executive submits the HSE results and associated assessments to the board together with the group's quarterly financial results. These results are posted on our intranet and internet sites. Quarterly HSE statistics are compiled and made accessible on our website through the performance report.

Our three group-wide performance indicators for safety are the Total Recordable Injury Frequency (TRIF), the Lost-Time Injury Frequency (LTIF) and the Serious Incident Frequency (SIF). These are reported quarterly at corporate level for Statoil employees and contractors. Statistics on our employees' sickness absence are reported annually.

The group-wide environmental indicators are reported annually at corporate level, with the exception of oil spills which are reported quarterly. The environmental indicators are reported for Statoil operated activities. This includes the Gassled facilities at Kårstø and Kollsnes, for which Gassco is operator, while Statoil is responsible for the technical operation (technical service provider).

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
We had six fatalities in 2009 in four different accidents. On 7 May 2009, we experienced a fatal accident in connection with the dismantling of scaffolding on Oseberg B, in which one of our contractor employees died. Three of our employees in Brazil were onboard Air France flight 447 which disappeared over the Atlantic on 1 June. On 7 September, a fatal accident occurred on the LPG carrier "Lady Shana" during a port call at Petit Couronne in France when a crew member fell from the shore gangway and into the river Seine. On 17 October, a fatality occurred when one of our contractors died on Statoil Canada's Leismer lease, located approximately 150 km south of Fort McMurray, Alberta.

The HSE accounting shows the development of the HSE performance indicators over the past five years. The use of resources, emissions and waste volumes for selected Statoil operated land-based plants and for Statoil-operated activities on the Norwegian continental shelf are shown in separate environmental overviews. See also the information on health, safety and the environment in the review of Statoil operations and the directors' report.

During 2009, our operations account for more than 154 million working hours (including contractors). These hours form the basis for the frequency indicators in the HSE accounting. Contractors handle a large proportion of the assignments for which Statoil is responsible as operator or principal enterprise.

Statoil's safety results with respect to serious incidents have been at a stable level in recent years. The overall Serious Incident Frequency (SIF) indicator decreased from 2.2 in 2008 to 1.9 in 2009.

There has been a decrease in the number of total recordable injuries per million working hours (TRIF) in 2009 (4.1) compared with 2008 (5.4). Contractor TRIF at year end 2009 was 4.8, and Statoil employee TRIF was 2.9. The lost-time injury frequency (injuries leading to absence from work) was 1.6 in 2009, a decrease from 2008 (2.1).

In addition to our HSE accounting at group level, the business units prepare more specific HSE statistics and analyses that are used in their own improvement efforts.

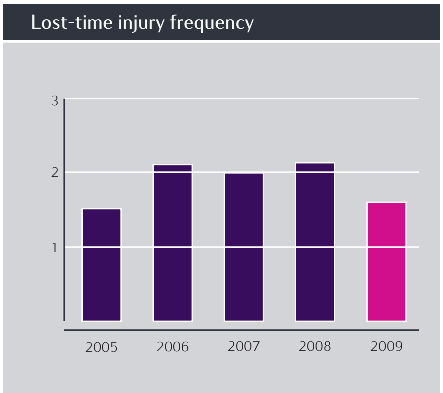
We were fined NOK 25 million by the public procecution authorities in Norway on 18 December 2009 in connection with an oil leakage incident that took place on 12 December 2007 on the Norwegian continental shelf. Statoil E&R has been fined a total of NOK 0.1 million in connection with approximately twenty minor issues related to, e.g,. food safety, the handling of liquid fuel and the transportation of dangerous goods. Statoil was fined NOK 2 million in December 2008 for a pollution of oil that occurred on 23 November 2005 on the Norne field, for not responding in accordance with the emergency preparedness plan.

HSE performance indicators

Here we present charts and statistics for our HSE performance indicators.

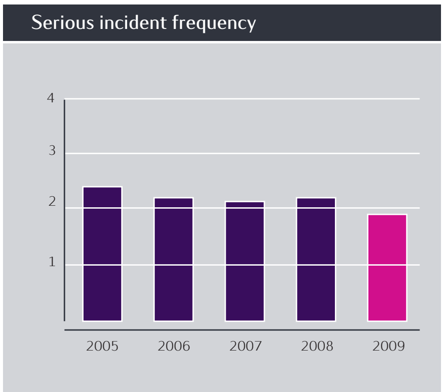
Definition: The number of fatalities, lost-time injuries, cases of alternative work necessitated by an injury and other recordable injuries, excluding first-aid injuries, per million working hours.

Developments: The total recordable injury frequency (including both Statoil employees and contractors) decreased from 5.4 in 2008 to 4.1 in 2009. For Statoil employees, the frequency decreased from 3.4 in 2008 to 2.9 in 2009, and for our contractors, the total recordable injury frequency decreased from 6.6 in 2008 to 4.8 in 2009.



Definition: The number of lost-time injuries and fatal accidents per million working hours.

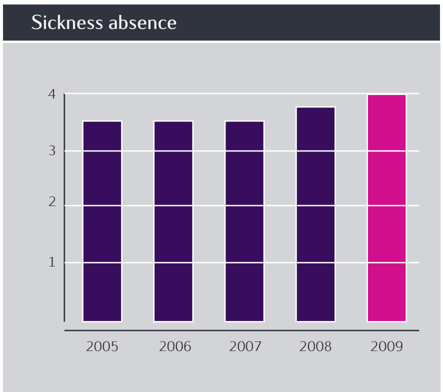
Developments: The lost-time injury frequency (including both Statoil employees and contractors) decreased from 2.1 in 2008 to 1.6 in 2009. The frequency for Statoil employees decreased from 1.7 in 2008 to 1.4 in 2009, and for our contractors, the lost-time injury frequency decreased from 2.3 in 2008 to 1.7 in 2009.



Definition: The number of incidents of a very serious nature per million working hours (1).

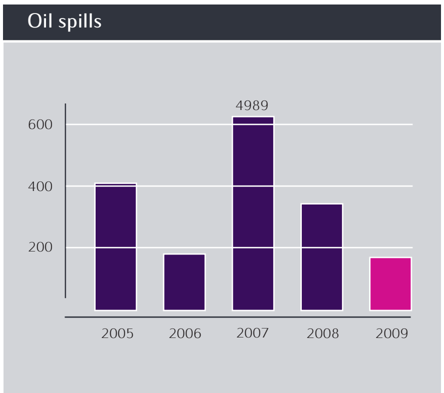
Developments: The serious incident frequency (including both Statoil employees and contractors) decreased from 2.2 in 2008 to 1.9 in 2009.

(1) 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, and this forms the basis for follow-up in the form of notification, investigation, reporting, analysis, experience transfer and improvement.



Definition: The total number of days of sickness absence as a percentage of possible working days (Statoil employees).

Developments: Sickness absence in Statoil increased from 3.7 % in 2008 to 4.0 % in 2009. At the same time, the reporting scope has increased and larger parts of the organisation are now included. Sickness absence in Statoil ASA in Norway has been stable in recent years at approximately 4.0 %. The sickness absence is closely followed up by managers at all levels.



Definition: Unintentional oil spills to the natural environment from Statoil operations (in cubic metres) (2).

Developments: The monthly average number of unintentional oil spills in 2009 is still stable. The total volume of spilled oil (net volume > 0) has however been reduced with about 50 % as compared to 2008.

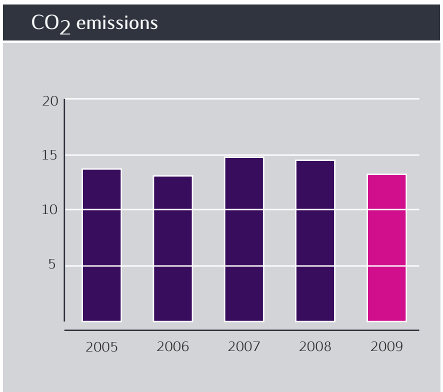
(2) All unintentional oil spills reaching the natural environment from Statoil operations are included in the figure.

Other spills

Definition: Other unintentional spills to the natural environment from Statoil operations (in cubic metres) (3).

Developments: The number of other unintentional spills (net volume > 0) in 2009 is at the same level compared to 2008. The total volume of spills in 2009 has however been reduced by nearly 35 % as compared to 2008.

(3) All unintentional spills of chemicals, produced water, ballast water and polluted water reaching the natural environment from Statoil operations are included.



Definition: Total emissions of carbon dioxide (CO2) in million tonnes from Statoil operated activities (4)

Developments: CO2 emissions decreased from 14.4 million tonnes in 2008 to 13.1 million tonnes in 2009. Both CO2 from energy production and CO2 from flaring have been reduced. This is mainly because of a reduction in Exploration and Production Norway of approx. 1.1 million tonnes CO2. International Exploration and Production has a reduction of approx. 0.2 million tonnes CO2 from 2008 to 2009. This is mainly due to reduced flaring at South Pars and production at Lufeng only first half 2009.

(4) 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.

Definition: Total emissions of nitrogen oxides (NOx) in thousand tonnes from Statoil operated activities (5)

Developments: NOx emissions decreased from 46.7 thousand tonnes in 2008 to 42.3 thousand tonnes in 2009. Both NOx from energy production and NOx from flaring have been reduced. All business areas have reduced their NOx emissions.

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

CH4 emissions

Definition: Total emissions of methane (CH4) from Statoil operated activities (6)

Developments: CH4 emissions were 32900 tonnes in 2009. CH4 emissions are approximately 10 % higher in 2009 compared to the year 2008. CH4 from energy production and methane from flaring has been reduced. CH4 from diffuse sources (including cold venting) has increased.

(6) CH4 emissions include CH4 from energy- and heat production in own plant, flaring (included well testing/well work over), cold venting, diffuse emissions and also storage and loading of crude oil.

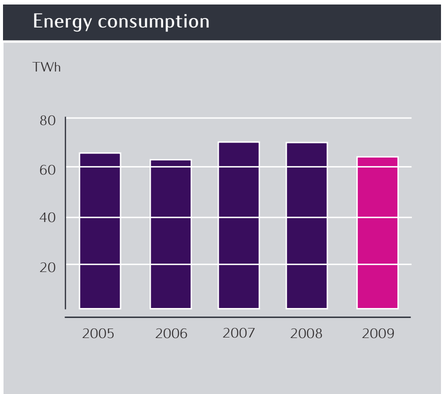
Global warming potential (GWP)

Definition: Global warming potential (GWP) is Statoil's share of greenhouse gas emissions from Statoil operated activities and activities operated by others (7)

Developments: GWP was 10.0 million tonnes CO2 equivalents for 2009. GWP has been at the same level through the year 2009.

(7) 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:

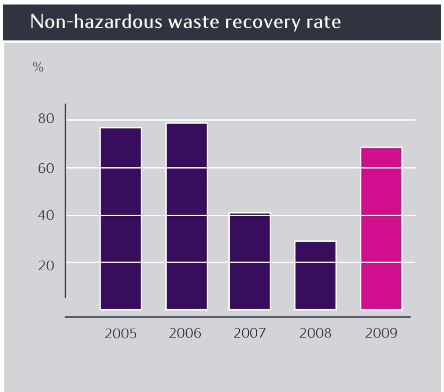
[1*(emissions of CO2)]+[21*(emissions of CH4)].



Definition: Total energy consumption in terawatt-hours (TWh) for Statoil operated activities (8)

Developments: Energy consumption decreased from 69.6 TWh in 2008 to 63.6 TWh in 2009. The energy consumption and the CO2 emissions basically follow the same pattern.

(8) 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 party and gross energy (heat and electricity) imported from contractor.



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 (9)

Developments: The non-hazardous waste recycling ratio has been at the same level (63-73 %) during 2009 and the average value for 2009 was 69 % .

(9) 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 re-use, recycled or incinerated with energy recovery.

Hazardous waste recovery rate

Definition: The hazardous waste recovery rate for 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 (10)

Developments: The amount of hazardous waste has increased by approx. 10% in 2009 compared to the year 2008. The waste recovery ratio has decreased from 86 % in 2008 to 61 % in 2009.

(10) The quantity of hazardous waste for recovery is the total quantity of hazardous waste from the plant's operations that has been delivered for re-use, recycled or incinerated with energy recovery (the total amount of hazardous waste, excluding hazardous waste sent to an approved deposition facility).

Environmental posters

Environmental posters for our land-based installations in Norway and Denmark.

NORWEGIAN CONTINENTAL SHELF [1)]

ENERGY	
Diesel	2,045 GWh
Electricity	314 GWh
Fuel gas	32,810 GWh
Flare gas	3,500 GWh

RAW MATERIALS	
Oil/condensate	92 mill. scm
Gas [2)]	114 bn. scm
Produces water	123 mill. m³

UTILITIES	
Chemicals process/prodn	61,900 tonnes
Chemicals drilling/well	363,750 tonnes

OTHER	
Fresh water consumption	416,800 m³

PRODUCTS	
Oil/condensate	92 mill. scm
Gas for sale	77 bn. scm

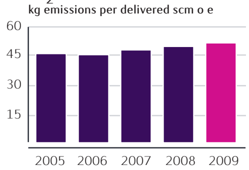
EMISSIONS TO AIR	
CO_2	8.5 mill.tonnes
nmVOC [3)]	29,430 tonnes
Methane [3)]	20,600 tonnes
NO_x	36,490 tonnes
SO_2	248 tonnes
Unintentional emissions of HC gas [4)]	23,800 kg

DISCHARGES TO WATER	
Produced water	105 mill. scm
Oil in oily water [5)]	1,226 tonnes
Produced water injected in the ground	26 mill. m³
Spills	
Unintentional oil spills	105 m³
Other unintentional spills	204 m³
Chemicals: [6)]	
Process/production	30,300 tonnes
Drilling/well	86,960 tonnes

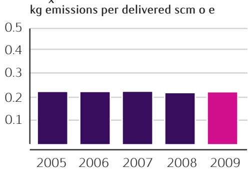
WASTE [7)]	
Non-hazardous waste for deposition	1,720 tonnes
Non-hazardous waste for recovery	11,550 tonnes
Non-hazardous waste recovery rate	86 %
Hazardous waste for deposition	37,000 tonnes
Hazardous waste for recovery	80,830 tonnes

[1)] Includes British part of Statfjord.
[2)] Includes fuel (3,0 bill. Sm³), flare (0,3 bill. Sm³) and gas injection (32,5 bill. Sm³).
[3)] Includes diffuse emissions, flare and engergy production.
[4)] Estimated values based on gas leakage rate and duration.
[5)] Includes oil from produced water, drain water, ballast water and jetting.
[6)] Includes 98,500 tonnes water and green chemicals/ingredients.
[7)] Includes waste from onshore bases. Waste from drilling represent 111,000 tonnes.

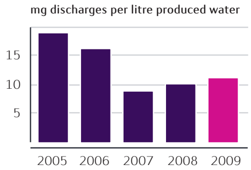
CO_2
kg emissions per delivered scm o e



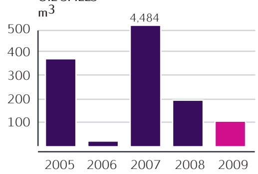
NO_x
kg emissions per delivered scm o e



OIL IN OILY WATER
mg discharges per litre produced water



OIL SPILLS
m3



SNØHVIT LNG INSTALLATION

ENERGY	
Electricity	104 GWh
Flare gas	926 GWh
Fuel gas	2680 GWh
Diesel	1.1 GWh

RAW MATERIALS	
Gas Snøhvit	4,030 mill scm
Condensate Snøhvit	0.6 mill scm

UTILITIES	
Amine	39.4 m³
Hydraulic fluids*	20 m³
Caustics	185 m³
Monoethylene glycol	0 m³
Other chemicals	90.7 m³

WATER CONSUMPTION	
Fresh water	115,000 m³

PRODUCTS	
LNG	5.20 mill scm
LPG	0.30 mill scm
Condensate	0.51 mill scm

EMISSIONS TO AIR	
CO_2	805,000 tonnes
NO_x	438 tonnes
H_2S	3.40 tonnes
SO_2	3.59 tonnes
nm VOC	748 tonnes
Methane	744 tonnes

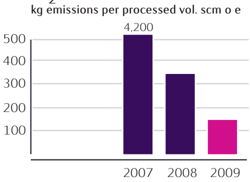
DISCHARGES TO WATER	
Treated water and open drain water	80,100 m³
Amine	0.22 tonnes
Ammonium	0.26 tonnes
BTEX	0.08 tonnes
Phenol	0.02 tonnes
Hydrocarbons	0.04 tonnes
TOC	1.36 tonnes
Heavy metals	0.01 tonnes

SPILLS	
Unintentional oil spills	0 m³
Other unintentional spills	1.02 m³

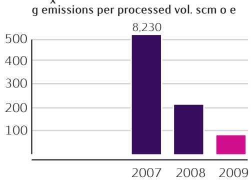
WASTE	
Non-hazardous waste for deposition	549 tonnes
Non-hazardous waste for recovery	531 tonnes
Non-hazardous waste recovery rate	49.2 %
Hazardous waste for deposition	337 tonnes
Hazardous waste for recovery	734 tonnes
Hazardous waste recovery rate	67.2 %

* Utilities include hydraulic fluids used in Hammerfest LNG Offshore/subsea part System 18
** Calculation of OE for produced LNG/LPG is done by using OLF factor for NGL; 1 tonn NGL = 1,9 Sm³ o.e.

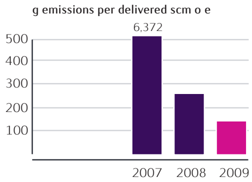
CO_2
kg emissions per processed vol. scm o e



NO_x
g emissions per processed vol. scm o e



nmVOC
g emissions per delivered scm o e



TJELDBERGODDEN

ENERGY	
Diesel	2 GWh
Electricity	233 GWh
Fuel gas	1,490 GWh
Flare gas	119 GWh

RAW MATERIALS	
Rich gas	416,000 tonnes

UTILITIES	
Caustics	286 tonnes
Acids	55 tonnes
Other chemicals	15 tonnes

WATER CONSUMPTION	
Fresh water	494,000 m³

PRODUCTS	
Methanol	711,000 tonnes
Oxygen	9,580 tonnes
Nitrogen	34,800 tonnes
Argon	14,000 tonnes
LNG	8,930 tonnes

EMISSIONS TO AIR [1]	
CO_2	316,000 tonnes
nmVOC	251 tonnes
Methane	581 tonnes
NO_x	217 tonnes
SO_2	0.6 tonnes
Unintentional emissions HC-gas	0 tonnes

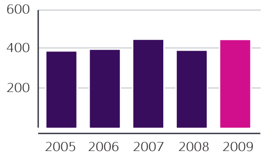
DISCHARGES TO WATER	
Cooling water	182 mill m³
Total organic carbon (TOC)	3.46 tonnes
Suspended matter	0.59 tonnes
Total-N	1.75 tonnes

SPILLS	
Unintentional oil spills	0.00 m³
Other unintentional spills	0.01 m³

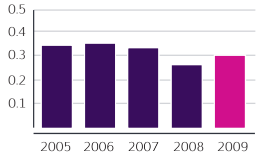
WASTE [2]	
Non-hazardous waste for deposition	42 tonnes
Non-hazardous waste for recovery	83 tonnes
Non-hazardous waste recovery rate	66 %
Hazardous waste for deposition	101 tonnes
Hazardous waste for recovery	24 tonnes
Hazardous waste recovery rate	19 %

[1] Figures for nmVOC/methane include emissions from flaring.
[2] Hazardous waste for deposition is sludge from the waste water treatment plant.

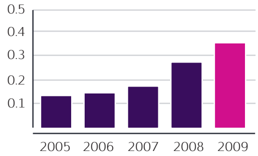
CO_2
kg emissions per tonne product
(methanol+LNG)



NO_x
kg emissions per tonne product
(methanol+LNG)



nmVOC
kg emissions per tonne product
(methanol+LNG)



MONGSTAD [1]

ENERGY	
Electricity consumption	503 GWh
Fuel gas and steam	6,600 GWh
Flare gas	204 GWh

RAW MATERIALS	
Crude oil	7,740,000 tonnes
Other process raw materials	3,130,000 tonnes
Blending components	232,000 tonnes

UTILITIES	
Acids	539 tonnes
Caustics	2,390 tonnes
Additives	1,890 tonnes
Process chemicals	4,040 tonnes

WATER CONSUMPTION	
Fresh water	4,510,000 m³

PRODUCTS	9,960,000 tonnes
Propane	Butane
Naphtha	Gas oil
Petrol	Petcoke/sulphur
Jet fuel	

EMISSIONS TO AIR	
CO_2	1,550,000 tonnes
SO_2	516 tonnes
NO_x	1,670 tonnes
nm-VOC refinery + CHP	6,890 tonnes
nm-VOC terminal	555 tonnes
Methane [2]	6,120 tonnes
Unintentional emissions of HC gas [3]	10 tonnes

DISCHARGES TO WATER	
Oil in oily water [4]	5 tonnes
Phenol	2 tonnes
Total Nitrogen [5]	52 tonnes
Total organic carbon (TOC)	86 tonnes
Suspended Solids (SS)	51 tonnes

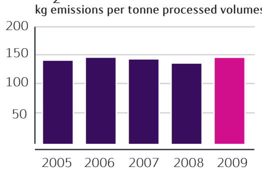
SPILLS	
Unintentional oil spills [6]	0.5 m³
Other unintentional spills [6]	1.1 m³

WASTE [7]	
Non-hazardous waste for deposition	1,670 tonnes
Non-hazardous waste for recovery	3,090 tonnes
Non-hazardous waste recovery rate	65 %
Hazardous waste for deposition	1,670 tonnes
Hazardous waste for recovery	16,100 tonnes
Hazardous waste recovery rate	91 %

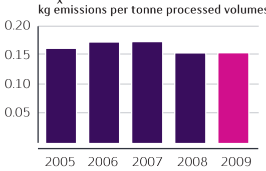
ENERGY	
Electricity produced [8]	15 GWh

[1] Included data for the refinery, crude oil terminal, Vestprosess facilities and Combined Heat and Power Plant (CHP).
[2] Reported methane emissions have risen from 2007/8 to 2009. Largely due to new factors derived from measurements by Spectrasyne in 2009. When looking at VOC as a sum of methane and nmVOC the emissions have decreased since 2007 (the emissions in 2008 were low because of RS-08). The nmVOC recovery unit does not recover methane.
[3] Included in nm-VOC refinery + CHP and Methane.
[4] Due to an icident in october 2008 the average of oil in oily water increased in 2008 and thus higher than the avreage in 2009.The effect of clearing of oily sludge in the water treatment plant seems to be good and the level of oil in oily water is lower than the level for the past six years.
[5] Includes Nitrogen from the water treatment plant and from scrubber A-4830 (SNCR plant).
[6] All spills are net values - to ground - none to water.
[7] Increase of 6% in total amount of non-hazardous waste from 2008 to 2009. Increase of 20% in total amount of hazardous waste from 2008 to 2009. Might be due to higher project activity on Mongstad in 2009, and no turnarounds this year.
[8] Electrisity produced in the CHP plant.

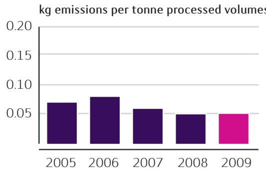
CO_2
kg emissions per tonne processed volumes



NO_x
kg emissions per tonne processed volumes



SO2
kg emissions per tonne processed volumes



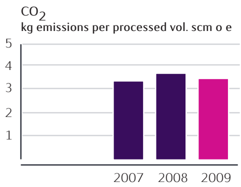
STURE PROCESSING PLANT

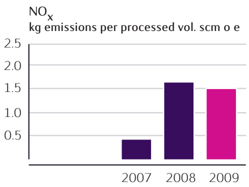
ENERGY	
Electricity	159 GWh
Flare gas	0.09 GWh
Fuel gas	351 GWh
Diesel	0.17 GWh

RAW MATERIALS	
Crude oil	23.4 mill scm

UTILITIES	
Hydrochloric acid	6.84 tonnes
Sodium hydroxide	10.6 tonnes
Methanol	418 m^3

WATER CONSUMPTION	
Fresh water	509,000 m^3





PRODUCTS	
LPG	757,000 scm
Naphta	448,000 scm

CRUDE OIL EXPORT	21.8 mill scm

EMISSIONS TO AIR	
CO_2	79,700 tonnes
NO_x	35.2 tonnes
Unintentional HC-gas emissions	0 tonnes
nmVOC	2,490 tonnes
Methane	309 tonnes

DISCHARGES TO WATER	
Treated water and open drain water	767,000 m^3
TOC	84.0 tonnes
Hydrocarbons	1.83 tonnes

SPILLS	
Unintentional oil spills	0 m^3
Other unintentional spills	0 m^3

WASTE	
Non-hazardous waste for deposition	35.7 tonnes
Non-hazardous waste for recovery	195 tonnes
Non-hazardous waste recovery rate	85.0 %
Hazardous waste for deposition	0.64 tonnes
Hazardous waste for recovery	46.7 tonnes
Hazardous waste recovery rate	99.0 %

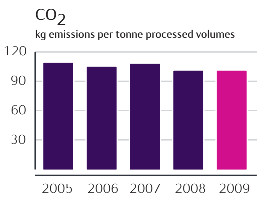
KALUNDBORG

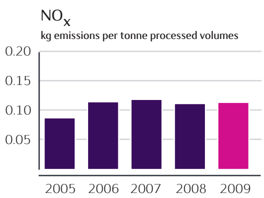
ENERGY	
Electricity	190 GWh
Steam	162 GWh
Fuel gas and oil	2,440 GWh
Flare gas	67 GWh

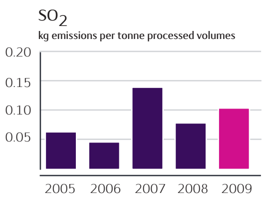
RAW MATERIALS	
Crude oil	4,750,000 tonnes
Other process raw materials	2,920 tonnes
Blending components	198,000 tonnes

UTILITIES	
Acids	662 tonnes
Caustics	1,140 tonnes
Additives	610 tonnes
Process chemicals	667 tonnes
Ammonia (liquid)	2,070 tonnes

WATER CONSUMPTION	
Fresh water	1,620,000 m^3







PRODUCTS	4,800,000 tonnes
Naphta	82,100 tonnes
Petrol	1,540,000 tonnes
Jet fuel	130,000 tonnes
LPG (butane, propane)	70,900 tonnes
Gas oil	1,780,000 tonnes
Fuel oil	361,000 tonnes
ATS (fertiliser)	6,500 tonnes
Fuel	836,000 tonnes

EMISSIONS TO AIR	
CO_2	502,000 tonnes
SO_2	512 tonnes
NO_x	559 tonnes
Methane	2,090 tonnes
nmVOC	4,790 tonnes
Unintentional emissions of HC gas	- tonnes

DISCHARGES TO WATER	
Oil in oily water	2.2 tonnes
Phenol	0.02 tonnes
Suspended matter	7 tonnes
Nitrogen	4.7 tonnes

SPILLS	
Unintentional oil spills	15.1 m^3
Other unintentional spills	0.11 m^3

WASTE	
Non-hazardous waste for deposition	50 tonnes
Non-hazardous waste for recovery	356 tonnes
Non-hazardous waste recovery rate	88 %
Hazardous waste for deposition	0 tonnes
Hazardous waste for recovery	5,240 tonnes
Hazardous waste recovery rate	100 %

KOLLSNES PROCESSING PLANT [1]

ENERGY

Electricity	1,130 GWh
Flare gas	109 GWh
Fuel gas	204 GWh
Diesel	0.51 GWh

RAW MATERIALS

Rich gas Troll A	19.2 bn scm
Rich gas Troll B	2.33 bn scm
Rich gas Troll C	2.93 bn scm
Rich gas Kvitebjørn	5.28 bn scm
Rich gas Visund	1.17 bn scm

UTILITIES

Monethylene glycol	1,030 m^3
Caustics	35 m^3
Other chemicals	119 m^3

WATER CONSUMPTION

Fresh water	67,400 m^3

PRODUCTS

Gas	31.0 bn scm
NGL	2.04 mill. scm

EMISSIONS TO AIR

CO_2	64,200 tonnes
NO_x	22 tonnes
CO	28 tonnes
nm VOC	546 tonnes
Methane	1,280 tonnes

DISCHARGES TO WATER

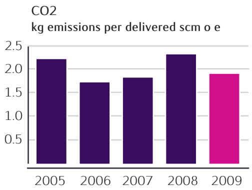
Treated water and open drain water	121,000 m^3
Total organic carbon (TOC)	1.29 tonnes
Monethylene glycol	1.23 tonnes
Methanol	0.06 tonnes
Hydrocarbons	0.06 tonnes
Ammonium	0.01 tonnes
Phenol	0.01 tonnes

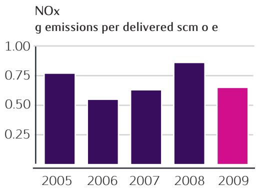
SPILLS

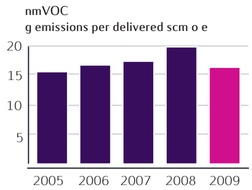
Unintentional oil spills	15 m^3
Other unintentional spills	0.02 m^3

WASTE

Non-hazardous waste for deposition	109 tonnes
Non-hazardous waste for recovery	400 tonnes
Non-hazardous waste recovery rate	79 %
Hazardous waste for deposition	158 tonnes
Hazardous waste for recovery	2,330 tonnes
Hazardous waste recovery rate	94 %







1) Gassco is the operator for the plant, but Statoil is the technical service provider (TSP).

KÅRSTØ GAS PROCESSING PLANT AND TRANSPORT SYSTEMS[1]

ENERGY [10) 11)]

Fuel gas	5,260 GWh
Electricity bought	720 GWh
Diesel	3 GWh
Flare gas	102 GWh

RAW MATERIALS [2)]

Rich gas (PP)	22.1 mill. tonnes
Condensate (PP)	2.81 mill. tonnes

UTILITIES

Hycrocloric acid	273 tonnes
Sodium hydroxide	247 tonnes
Ammonia [13)]	15.1 tonnes
Methanol	117 tonnes
Other chemicals	8.2 tonnes

WATER CONSUMPTION

Fresh water (PP)	0.9 mill m^3

PRODUCTS

Lean gas	18.4 mill tonnes
Propane	2.65 mill tonnes
I-butane	0.54 mill tonnes
N-butane	1.05 mill tonnes
Naphtha	0.70 mill tonnes
Condensate	1.53 mill tonnes
Ethane	0.88 mill tonnes
Electricity sold	38 GWh

EMISSIONS TO AIR [3) 4) 5) 6) 7)]

SO_2	6.60 tonnes
NO_x	705 tonnes
nmVOC	1640 tonnes
Metane	1130 tonnes
CO_2	1,140,000 tonnes
Unintentional HC-gas emissions	0 tonnes

DISCHARGES TO WATER

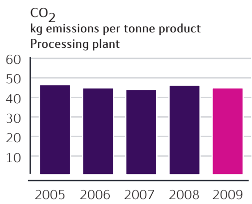
Cooling water	396 mill m^3
Treated water	1.13 mill m^3
Oil in oily water	338 kg
Total organic carbon (TOC)	3.9 tonnes

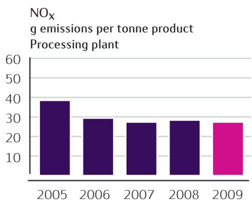
SPILLS

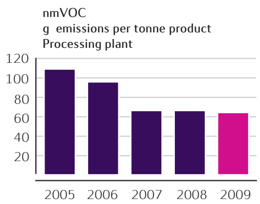
Unintentional oil spills	0.17 m^3
Other unintentional spills	0.75 m^3

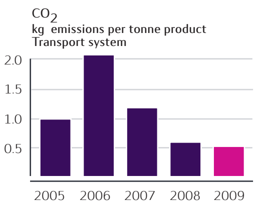
WASTE [8) 9) 12)]

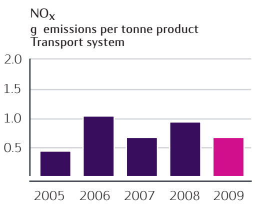
Non-hazardous waste for deposition	247 tonnes
Non-hazardous waste for recovery	2,510 tonnes
Non-hazardous waste recovery rate	91.0 %
Hazardous waste for deposition	7.3 tonnes
Hazardous waste for recovery	629 tonnes
Hazardous waste recovery rate	98.9 %

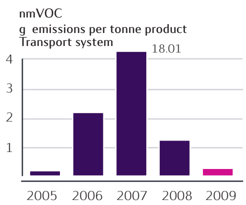












1) Gassco AS is operator for the plant, but Statoil is the technical service provider (TSP)
2) Except gas transport from TN Draupner: 26,3 mill tonnes
3,4,5,6,7) Included emissions from Draupner: SO2: 0,08 tonnes, NOx: 17 tonnes, nmVOC: 7 tonnes, CH4: 32 tonnes, CO2: 13 339 tonnes
8) Non Hazardous waste included from Draupner: 15,2 tonnes for deposition and 133 tonnes for recovery
9) Hazardous waste included from Draupner: 7 kg for deposition and 95,4 tonnes for recovery
10) Included energy from Draupner: 64 GW from fuel gas, 1 GW from diesel and 1 GW from flare gas
11) All energy is reported as gross energy from 2009
12) Hazardous waste includes processwater and puraspec mass
13) Included the amount of ammonia in the chemical «Salmiakksprit»

Recommendation of the corporate assembly

Resolution:
At its meeting of 25 March 2010 the corporate assembly discussed the 2009 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, 25 March 2010

Olaug Svarva
Chair of the corporate assembly

Corporate assembly
Olaug Svarva, Idar Kreutzer, Karin Aslaksen, Greger Mannsverk, Steinar Olsen, Benedicte Berg Schilbred, Ingvald Strømmen, Inger Østensjø, Rune Bjerke, Kåre Rommetveit, Tore Ulstein, Per Helge Ødegård, Eldfrid Irene Hognestad, Stig Lægreid, Per Martin Labråthen, Jan-Eirik Feste, Anne K. S. Horneland

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Photo: Harald Pettersen