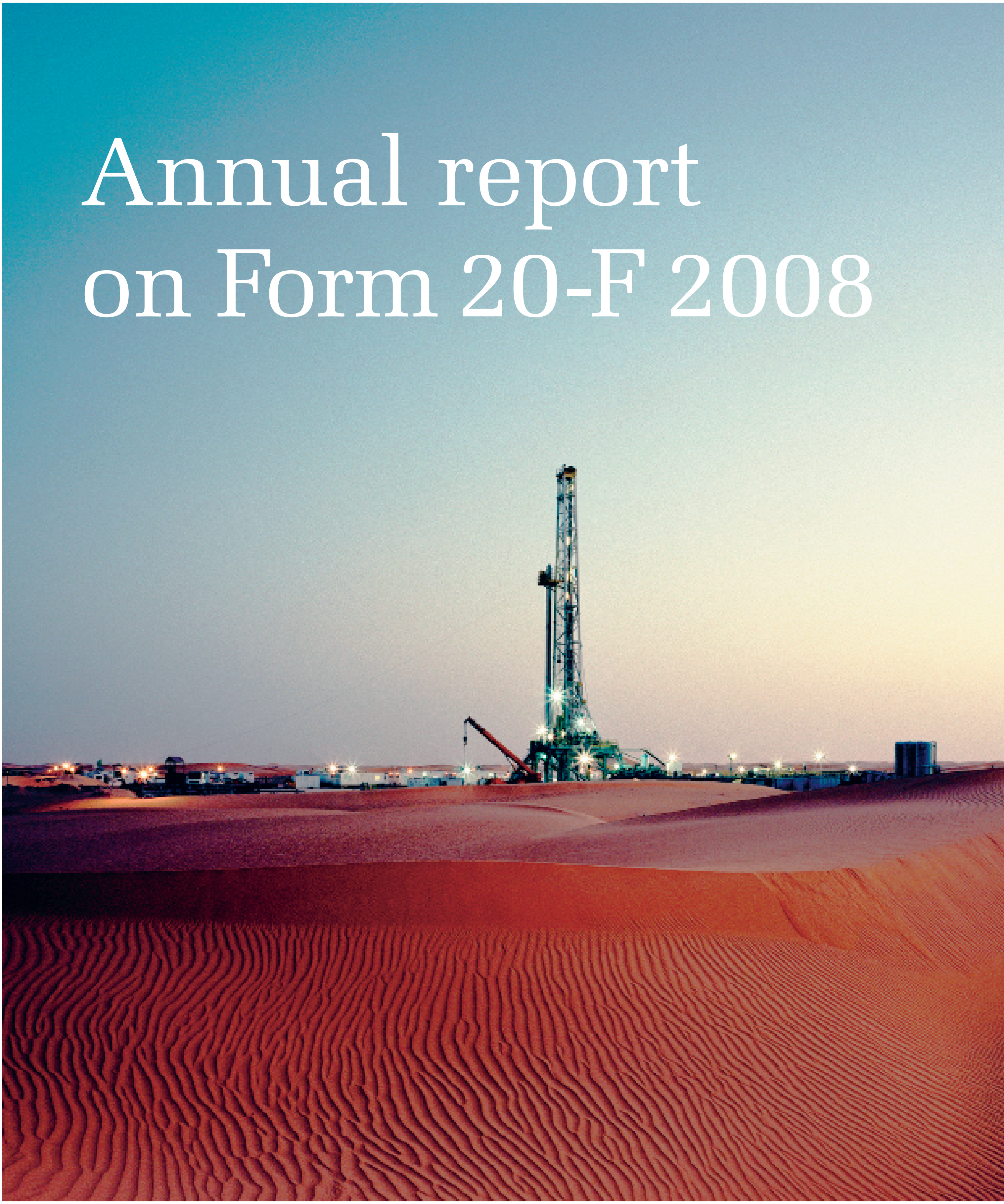
Annual report on Form 20-F 2008



StatoilHydro

Annual Report on Form 20-F

1 Introduction

1.1 Frontpage

STATOILHYDRO ANNUAL REPORT ON FORM 20-F

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 20-F
(Mark one)

_ REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12 (g)
OF THE SECURITIES EXCHANGE ACT OF 1934
OR
X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2008
OR
_ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition period from _________ to ____________
OR
_ SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
Date of event requiring this shell company report__________

Commission File No. 1-15200

StatoilHydro ASA
(Exact Name of Registrant as Specified in Its Charter)
N/A
(Translation of Registrant's Name Into English)

Norway
(Jurisdiction of Incorporation or Organization)

Forusbeen 50, N-4035 Stavanger, Norway
(Address of Principal Executive Offices)

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

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

Title of each class	Name of each exchange on which registered
American Depositary Shares	New York Stock Exchange
Ordinary shares, nominal value of NOK 2.50 each	New York Stock Exchange*

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

Securities registered or to be registered pursuant to Section 12(g) of the Act: None
Securities for which there is a reporting obligation pursuant to Section 15 (d) of the Act: None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the Annual Report:

Ordinary shares of NOK 2.50 each	3,184,865,894

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

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

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

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

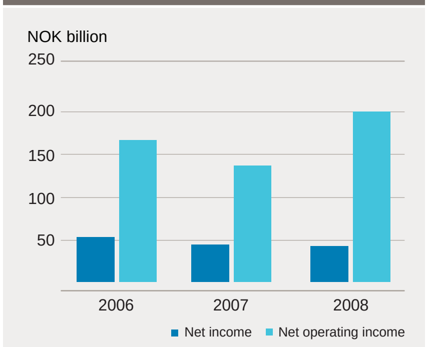
Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:
U.S. GAAP __ International Financial Reporting Standards as issued by the International Accounting Standards Board _X_ Other __

If “Other” has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.
Item 17 __ Item 18 __

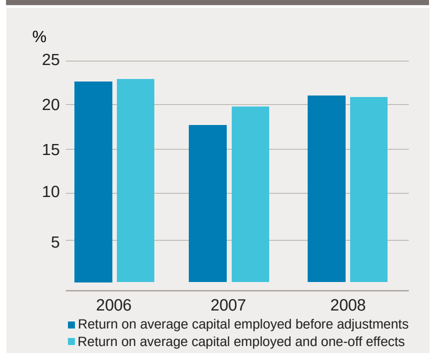
If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes__   No _X_

1.2 Key figures

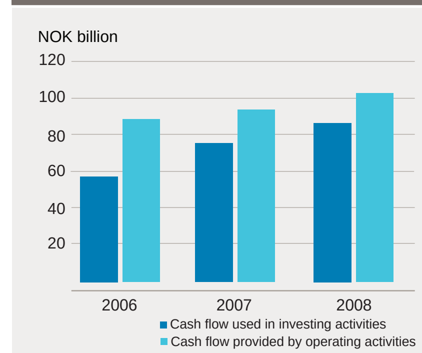
INCOME



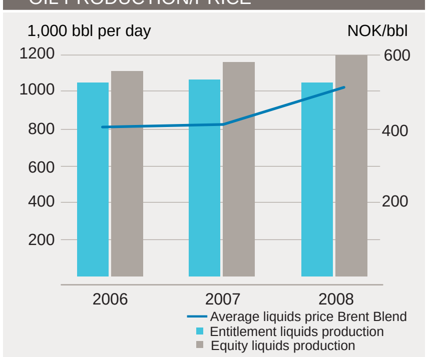
RETURN



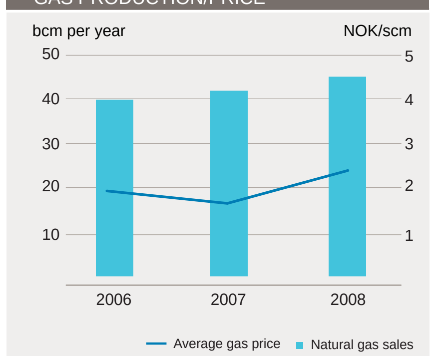
CASH FLOW



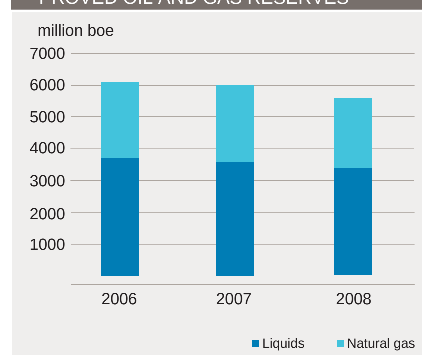
OIL PRODUCTION/PRICE



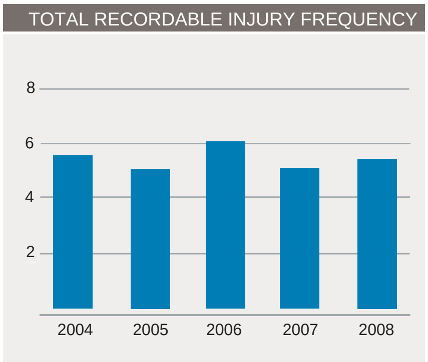
GAS PRODUCTION/PRICE



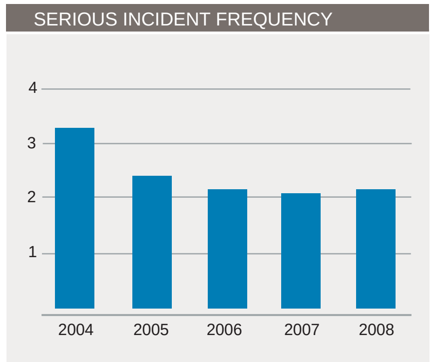
PROVED OIL AND GAS RESERVES



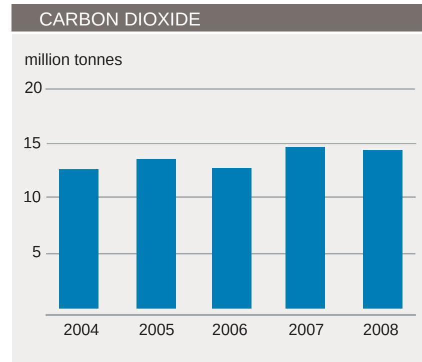
TOTAL RECORDABLE INJURY FREQUENCY



SERIOUS INCIDENT FREQUENCY



CARBON DIOXIDE



1.3 About the report

StatoilHydro's Annual Report on Form 20-F for the year ended 31 December 2008 ("Annual Report on Form 20-F") is available online at www.statoilhydro.com. StatoilHydro is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, StatoilHydro files its Annual Report on Form 20-F and other related documents with the Securities and Exchange Commission, the SEC. It is also possible to read and copy documents that have been filed with the SEC at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549, USA. You may also call the SEC at 1-800-SEC-0330 for further information about the public reference rooms and their copy charges, or you may log on to www.sec.gov. The report can also be downloaded from the SEC website at www.sec.gov.

StatoilHydro discloses on its website at www.statoilhydro.com/en/aboutstatoilhydro/corporategovernance/norwegiancodeofpractice/pages/statementofdifference.aspx, and in its Annual Report on Form 20-F (Item 16B) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under the New York Stock Exchange (the "NYSE") listing standards.

1.4 Financial highlights

StatoilHydro publishes financial data in accordance with IFRS. StatoilHydro did not publish financial data in accordance with IFRS in 2006 as we previously presented financial data in accordance with US GAAP. For this reason, we have not provided selected financial data for 2005 and 2004 in this Annual Report on Form 20-F 2008. Selected financial data for those years presented in accordance with US GAAP is included in our 2006 Annual Report on Form 20-F.

	For the year ended 31 December		
(in NOK billion, unless stated otherwise)	**2008**	**2007**	**2006**
Financial information			
Total revenues	**656.0**	522.8	521.5
Net operating income	**198.8**	137.2	166.2
Net income	**43.3**	44.6	51.8
Cash flow provided by operating activities	**102.5**	93.9	88.6
Cash flow used in investing activities	**85.8**	75.1	57.2
Interest-bearning debt	**75.3**	50.5	54.8
Net interest-bearing debt	**46.0**	25.5	43.8
Total assets	**578.4**	483.2	458.8
Net assets	**216.1**	177.3	167.8
Share Capital	**8.0**	8.0	8.0
Minority Interest	**2.0**	1.8	1.6
Net debt to capital employed	**17.5%**	12.4%	20.5%
Return on average capital employed after tax	**21.3%**	17.9%	22.9%
Operational information			
Combined equity oil and gas production (thousand boe/day)	**1,925**	1,839	1,778
Proved oil and gas reserves (million boe)	**5,584**	6,010	6,101
Reserve replacement ratio (three-year average)	**60%**	81%	76%
Production cost (NOK/boe)	**38.1**	44.1	28.4
Share information			
Ordinary and diluted earnings per share	**13.58**	13.80	15.82
Share price at Oslo Stock Exchange on 31 December	**113.90**	169.00	165.25
Dividend paid per share [1]	**7.25**	8.50	9.12
Dividend paid per share USD [2]	**1.04**	1.22	1.31
Weighted average number of ordinary shares outstanding	**3,185,953,538**	3,195,866,843	3,230,849,707

[1] See Sharebolder information section for a description of how dividends are determined and share repurchases.

[2] USD figure presented using Federal Reserve Bank of New York 2008 year end noon buying rate for Norwegian kroner was USD 1.00 = 6.9756 NOK.

1.5 Important events in 2008

Business development

- On 21 February, Gazprom, Total and StatoilHydro signed a Shareholder Agreement for the creation of Shtokman Development AG for phase one of the Shtokman field.
- StatoilHydro ASA and Det norske oljeselskap ASA signed a sales and purchase agreement on 12 October for the transfer of Det norske oljeselskap's 15% interest in the Goliat field to StatoilHydro ASA. The transaction has effect from 1 January 2008. Also on 12 October, StatoilHydro Petroleum AS and Det norske oljeselskap ASA agreed on a swap of minor interests in three other licences.
- On 21 October, the European Commission announced that StatoilHydro has been granted permission to take over the bulk of the Jet retail chain in Scandinavia currently owned and operated by ConocoPhillips.
- On 12 November StatoilHydro formed a strategic alliance with Chesapeake Energy Corporation to jointly explore unconventional gas opportunities worldwide. Under this agreement we will initially acquire a 32.5% interest in Chesapeake's Marcellus shale gas acreage.
- On 11 December StatoilHydro completed the full acquisition of the Peregrino heavy-oil field offshore Brazil, after closing the deal to acquire the additional 50% stake from Anadarko and making StatoilHydro the operator.

Access to new areas

- Internationally, StatoilHydro was the high bidder on 16 leases, of which 14 were joint bids with ENI Petroleum, in the Chukchi Sea Lease Sale 193 in Alaska announced on 6 February. StatoilHydro will be the operator of all 16 leases. In total, the group gained access to 20 new exploration licences during the year in the Gulf of Mexico, Alaska, Brazil, Canada and the Faroe Islands.
- In Norway, StatoilHydro was offered interests in 12 production licences in the Awards of Predefined Areas 2007 (APA 2007) on the Norwegian Continental Shelf (NCS). The company will be the operator of nine of the licences

Exploration activities

- StatoilHydro delivered an extensive exploration programme in 2008. Of a total of 79 exploration wells completed before 31 December 2008, 40 were drilled outside the NCS. Thirty-five wells were discoveries, of which eight are located outside the NCS. An additional eight wells have been completed since 31 December 2008.

Project development

- StatoilHydro maintained a high activity level in progressing projects into production. On 18 January, the plan for development and operation (PDO) of Yttergryta was submitted, only six months after the discovery was made. In 2008, StatoilHydro delivered three PDOs (Plan for Development and Operation) on the NCS: Yttergryta (18 January), Morvin (15 February) and the Troll Field project (27 June).
- Production from Gamma Main Statfjord on the Oseberg field in the North Sea commenced on 12 April, only 18 months after the oil deposit was proved. Production started from seven fields on the NCS during 2008: Volve (12 February), Gulltopp (7 April), Oseberg Gamma Main Statfjord (12 April), Vigdis East (15 April), Theta Cook (26 June), Oseberg Delta (27 June) and Vilje (1 August). Internationally, production commenced on Mondo in Angola (1 January), Deep Water Gunashli in Azerbaijan (22 April), Saxi and Batuque offshore Angola (1 July), the Agbami in Nigeria (29 July) and South Pars in Iran (1 October).

Production

- Total equity production increased by 5% from 2007 to 1,925 mboe per day in 2008. Total liquids and gas entitlement production increased by 2% from 1.724 mboe per day in 2007 to 1,751 mboe per day in 2008.

Market

- The first cargo of gas from the NCS arrived in the strategically important markets in the USA on 21 February and in Japan on 22 March.
- Gas filling into the storage caverns in the Aldbrough project in the UK started in August. This is a cooperation project for natural gas storage between the British company SSE Hornsea Limited (SSEHL) and StatoilHydro.

Technology and new energy

- StatoilHydro established a a research and development centre in Alberta, Canada to support the group's heavy oil business world-wide. In creating the Heavy Oil Technology Centre (HOTC), StatoilHydro will explore academic partnerships and work with government and industry institutions, just as it has done in its operations in Norway and around the world.
- The most complicated well in StatoilHydro's history was successfully completed and hydrocarbons were flowing up through the well at 9910 metres. This is thus the longest producing well in the world drilled from an offshore platform. The well provides the company with valuable knowhow.

Social responsibility and sustainable development

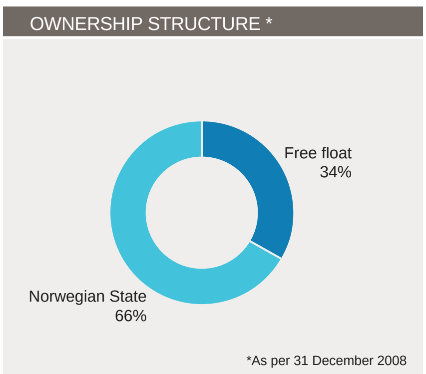
- StatoilHydro decided to build the world's first full scale floating wind turbine, and test it over a two-year period offshore Karmøy.
- Production resumed on the Statfjord A platform 28 May, after four days of shutdown due to an oil leak Saturday 24 May. For safety reasons, a total of around 1,200 cubic metres of oil-containing water were pumped to sea. This was done to ensure safety on board the platform following a leak in a pipe inside one of the shafts of the installation. Oil protection equipment and oil booms were deployed to collect a thin oil film around the Statfjord A platform.

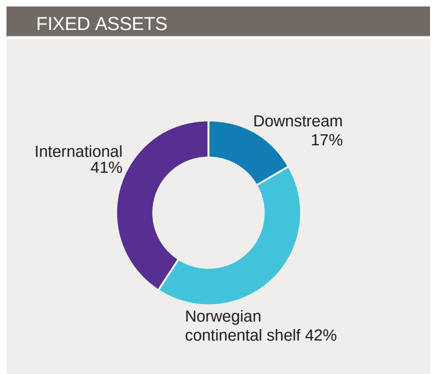
- StatoilHydro submitted an external investigation report on the Libya matter to Norwegian and US authorities on 7 October. Consultancy agreements related to Norsk Hydro's earlier activities in Libya contain issues which could be problematic in relation to Norwegian and US anti-corruption legislation. The report has been submitted to the National Authority for Investigation and Prosecution of Economic and Environmental Crime in Norway (Økokrim), to the US Department of Justice (DoJ), the US Securities and Exchange Commission (SEC) and to the relevant Libyan authorities.
- StatoilHydro and Indian oil company ONGC agreed on 6 February to jointly explore the potential of developing Carbon Capture and Storage (CCS), and CDM (clean development mechanism) projects in India.
- Carbon injection and storage on the Snøhvit field started on 22 April. Instead of emitting the carbon dioxide (CO2) resulting from the well stream that comes from the Snøhvit field to the air, the CO2 is reinjected into the ground and stored in a formation which lies somewhat beneath the gas-bearing formations on the Snøhvit field.
- StatoilHydro submitted a plan for carbon capture at Mongstad to the Ministry of Petroleum and Energy and the Ministry of the Environment. The plan addresses the most important challenges and sums up key issues associated with the technical feasibility of carbon capture at Mongstad. This is the first step along the way towards full-scale carbon capture at Mongstad.

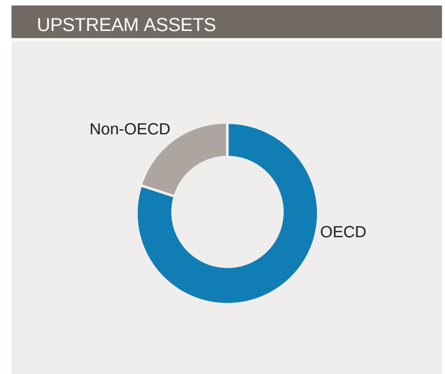
2 Business overview

2.1 Our business

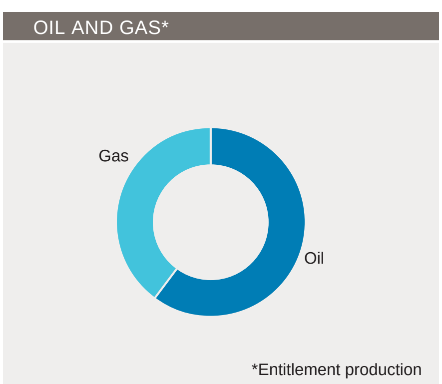
StatoilHydro is an integrated oil and gas company based in Norway and present in approximately 40 other countries worldwide. We are the leading operator on the NCS and are also enjoying strong growth in our international production.







StatoilHydro ASA is a public limited company organised under the laws of Norway and is subject to the provisions of the Norwegian act relating to public limited liability companies (the Norwegian Public Limited Companies Act).



Entitlement oil and gas production outside Norway represented 17% of our total output, which averaged 1.751 mmboe per day in 2008.

As of 31 December 2008, we had proved reserves (including our share of reserves in affiliated companies of 127 mmbbl of oil) of 2201 mmbbl of oil and 537.8 bcm (equivalent to 19.0 tcf) of natural gas, corresponding to aggregate proved reserves of 5584. mmboe.

We are represented in approximately 40 countries and are engaged in exploration and production activities in 24 of them. As of 31 December 2008, we had approximately 29,500 employees.

We rank among the world's largest net sellers of crude oil and condensate and we are the second largest supplier of natural gas to the European market.

We have substantial processing and refining activities and approximately 2300 service stations in Scandinavia, Poland, the Baltic States and Russia.

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

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

Business address
Our business address is Forusbeen 50, NO-4035 Stavanger, Norway. Our telephone number is +47 51 99 00 00. Our largest office locations are Stavanger, Bergen and Oslo.

The StatoilHydro group and the main business and functional areas are presented in the following sections.


Canada
USA
Mexico
Cuba
Venezuela
Brazil
Faroe Islands
United Kingdom
Ireland
Norway
Sweden
Finland
Denmark
Germany
Belgium
Poland
Estonia
Latvia
Lithuania
Russia
Kazakhstan
Azerbaijan
Turkmenistan
Turkey
Morocco
Algeria
Libya
Egypt
Jordan
Iraq
Iran
Qatar
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India
China
Nigeria
Tanzania
Angola
Singapore
Indonesia
Australia
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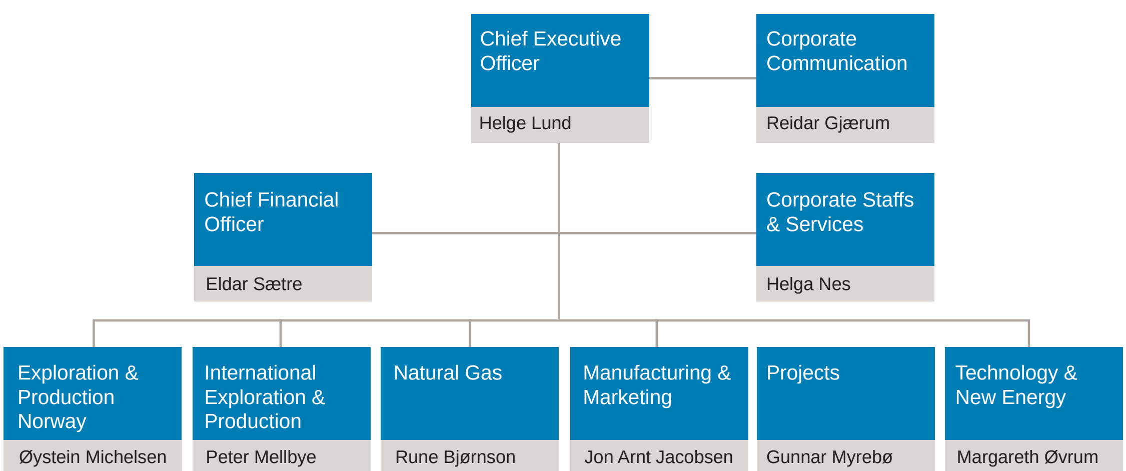

Chief Executive Officer
Helge Lund
Corporate Communication
Reidar Gjærum
Chief Financial Officer
Eldar Sætre
Corporate Staffs & Services
Helga Nes
Exploration & Production Norway
Øystein Michelsen
International Exploration & Production
Peter Mellbye
Natural Gas
Rune Bjørnson
Manufacturing & Marketing
Jon Arnt Jacobsen
Projects
Gunnar Myrebø
Technology & New Energy
Margareth Øvrum

2.2 Our history

Statoil was founded in 1972 and merged with Hydro's oil and energy business in 2007. We changed our name to StatoilHydro on 1 October, 2007.

Statoil ASA (Statoil) was founded by a decision of the Norwegian Storting (parliament) in 1972. As a result of Statoil's merger with the oil and energy business of Hydro (formerly Norsk Hydro), we have roots in the oil industry dating back to the 1960s when Hydro took part in the exploration of the NCS.

Statoil was incorporated as a limited company under the name Den norske stats oljeselskap a.s. Wholly-owned by the Norwegian State, the company's role was to be the government's commercial instrument in the development of the oil and gas industry in Norway. In 2001, the company became a public limited company listed on the Oslo and New York stock exchanges, and changed its name to Statoil ASA.

On 1 October 2007, the oil and energy assets of Hydro were merged with Statoil, and the company changed its name to StatoilHydro ASA. Through this merger, our ability to fully realise the potential of the NCS was strengthened and our chances of succeeding as an international player improved. As a result of the merger, we are the largest international oil and gas company operating in water deeper than 100 metres. The financial and other information in this report reflects the development of the former Statoil and Hydro on a carry over or combined basis for all periods presented.

Our history of involvement in the oil and gas industry began in earnest in 1965, when we were awarded licences by the Norwegian State to explore for petroleum on the NCS. We participated in the discovery of the Ekofisk field in 1969 and the Frigg field in 1971. The development of these discoveries brought us into the petroleum refining and marketing business.

In 1975, oil refining operations began at Mongstad in Norway, and in 1974, Mobil discovered the Statfjord field in the North Sea, which was of great significance for the further development of the Norwegian Continental Shelf (NCS). During the development of Statfjord, one of the world's largest offshore oilfields, we encountered great challenges. Statfjord came on stream in 1979 and we took over as operator eight years later. Today, we have a 44% interest in the field.

In the 1980s, both Statoil and Hydro became major players in the European gas market by obtaining large sales contracts for the development and operation of gas transport systems and terminals. During the same decade, we were heavily involved in manufacturing and marketing in Scandinavia and we established a comprehensive network of service stations. We acquired Esso's service stations, refineries and petrochemical facilities in Denmark and Sweden.

The 1990s were characterised by intense technological development on the NCS. Both Statoil and Hydro became leading companies in the fields of floating production facilities and subsea developments. We grew strongly, expanded in product markets and increased our commitment to international exploration and production through our alliance with BP. The foundations for the today's merged company were also laid with Hydro's acquisition of Saga Petroleum in 1999, and several major acquisitions in the Gulf of Mexico.

Since 1 October 2007, our business has grown as a result of substantial investments and acquisitions including the acquisitions of oil sand leases in Canada in 2007, and the acquisition of the remaining share in the Peregrino field in Brazil completed in 2008, for which field we also became the operator. Since October 2007 we also have had a 24% ownership share in Shtokman Development AG which is responsible for phase I of the Shtokman development a natural gas field located in the central part of the Russian sector of the Barents Sea.

Our most recent transaction involves a strategic agreement to jointly explore unconventional gas opportunities worldwide with Chesapeake Energy Corporation, the largest US producer of natural gas. Under these agreements StatoilHydro acquired an initial 32.5% interest in Chesapeake's Marcellus shale gas acreage covering 1.8 million net acres (7300 square kilometres) in the Appalachia region of the northeastern USA. For more information of this acquisition, see report section 3.2 Operational review-International E&P.

2.3 Statements on competitive position

Statements referring to StatoilHydro's competitive position rely on a range of sources, including analysts' reports, independent market studies and our internal assessments of our market share.

Statements referring to StatoilHydro's competitive position in the Business Overview and Operational Review sections are based on what we believe to be true and, in some cases, they rely on a range of sources, including investment analysts' reports, independent market studies and our internal assessments of our market share based on publicly available information about the financial results and performance of market players.

2.4 Strategy

In StatoilHydro we are working towards our goals of continuing our strategy for profitable growth and upholding our ambition to increase equity production of oil and gas to 2012 and beyond, despite great uncertainty in the global economy and oil market.

In working towards our ambition to realise the full value potential of the NCS, we are developing international platforms for long-term growth, and we are gradually building a position within new energy. The company is well positioned to manage through the global economic downturn. A strong balance sheet and active cost management will enable the company to pursue this long term strategic direction.

2.4.1 Business environment

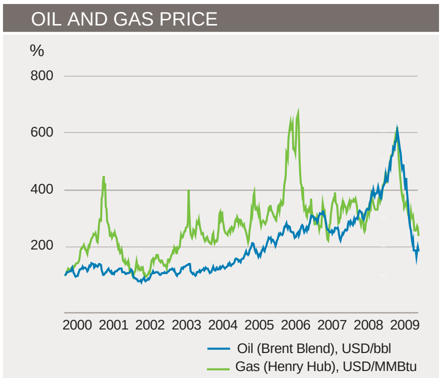
The global economy entered into recession in the second half of 2008. Nevertheless, energy demand is expected to pick up and energy prices are expected to increase in the longer term.

Macroeconomic outlook

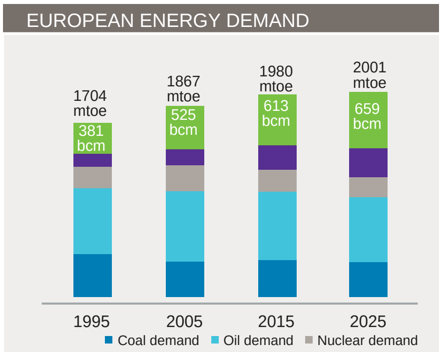
The global economy entered into recession in the second half of 2008, and signs of a cyclical downturn in the real economy were evident at the beginning of the year, led by falling housing prices in the US and several European countries. The downturn was reinforced by the financial crisis that escalated in September. A vast deleveraging in both household and corporate sector will lead to slowing growth rates in consumer spending and investments in all regions.

Global GDP growth is currently expected to be negative in 2009. Within two to three years we expect global growth to return to the long term trend, within the range of 2.5 to 4%. The impact of the policy measures and government stimulus packages is unknown and intended positive effects therefore represent considerable uncertainties for these forecasts.

OIL AND GAS PRICE



EUROPEAN ENERGY DEMAND



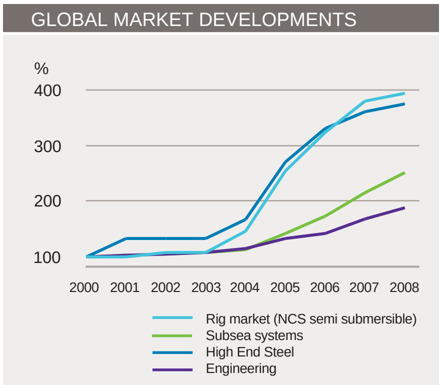
Source: IEA WEO 2008 Reference Scenario World, OECD Europe

Crude oil price developments

Dated Brent entered into 2008 on a strong upward trend extending from 2007, and accelerated as financial investors increased positions in a search for more favourable yields. Strong support from a tight gasoil/diesel market and declining crude oil inventories led to an increasingly tight oil market, and the Brent dated reached a record high level of 144 USD/bbl in July 2008.

At this point an underlying tendency of slower global GDP growth and weakening product demand started to discourage investors. With a shift of both sentiment and outlook during 2008, crude oil prices were fundamentally different from the first half to the second and traded between 33 and 40 USD/bbl in December. Brent dated averaged 97.26 USD per barrel in 2008. The gas, power and EU ETS (Emission Trading Scheme) prices have broadly followed oil prices through 2008.

With the global economy deteriorating, the energy markets are expected to stay relatively weak in 2009 and possibly into 2010 and 2011. Over time as the macro economic situation improves, energy demand is expected to pick up and energy prices are expected to rise.



High cost environment

In recent years, the oil industry has focused largely on growing production and the resource base. As energy prices soared and the competition for resources intensified, the cost of building new production capacity increased steeply. The tightening of the supplier market intensified the cost push. With reduced oil demand and falling oil prices, this high cost environment is not seen as sustainable. If the oil price remains at current low levels, we expect costs to be reduced going forward.

2.4.2 A strategy for value creation and growth

StatoilHydro is continuing its strategy for value creation and growth and upholding its ambition to increase the equity production of oil and gas up to 2012, despite great uncertainty in the global economy and the oil market.

Overall strategic direction

Our long-term strategy remains unchanged, and we are taking firm action to manoeuvre through the current turmoil. StatoilHydro's strategy is to create shareholder value as an upstream-oriented, and technology-based energy company. This strategy can be summarised as:

- Maximising long-term value creation on the NCS
- Building and delivering profitable international growth
- Developing profitable midstream and downstream positions
- Creating a platform for new energy solutions and production

In the short term, our main focus will be on delivering on our production targets and managing our cost base. This means delivering high operational performance, with a strong focus on HSE. In the longer term our focus is to develop the current project portfolio with quality and at a competitive cost to enable us to grow profitably.

Leveraging our technology and capabilities

There are four areas of high potential in which StatoilHydro has competitive advantages and the experience to face challenges and capture opportunities:

- Deep waters: We already have a relatively significant exposure to six of the most interesting deep water basins in the world - the Gulf of Mexico, Brazil, Angola, Nigeria, Norway and Indonesia.
- Harsh environments: Examples are Shtokman, Goliat, and Snøhvit. We see the resource potential of the Arctic as particularly interesting, although it is a region that is not expected to deliver results until the medium to longer term due to the technical and environmental challenges.
- Heavy oil: For example the Grane field in Norway, the oil sands position in Canada, heavy oil in Venezuela, and more conventional offshore heavy oil projects in Brazil and the United Kingdom.
- Gas value chain: This category includes liqueified Natural Gas (LNG) and unconventional gas from the US shale gas transaction.

Maximising long-term value creation on the NCS

StatoilHydro has a unique position on the NCS, where we operate 39 fields and produce more than three mmboe per day of production. We have a strong presence in all NCS regions and operate around one-third of the NCS's expected reserves. We expect that our asset base, experience and technical leadership will enable us to fully utilise these resources. We anticipate the NCS portfolio will continue to be a core activity area, income generator and technology base for many years to come. We believe that significant exploration potential remains and we aim to maintain our position as the main industrial architect.

We are focused on improving our HSE performance, regularity and drilling efficiency, and we plan to use Improved Oil Recovery (IOR) measures and other operational best practices to maximise the potential of our assets. We intend to highgrade our portfolio, through acquisitions and divestments.

Building and delivering profitable international growth
We anticipate that StatoilHydro's growth beyond 2012 will take place mainly outside the NCS. Our short- to medium-term focus is on delivering a high quality project portfolio to a high quality and on time and within budget. After the merger, we are a stronger company with increased capacity and a larger resource pool of finances and employees, well positioned to pursue further international growth. In the longer term, we expect that our international asset base will transform the structure and profile of our company, allowing us to grow and become more diversified, both in geographical terms and in types of production.

We will use our core expertise in areas such as deep waters, harsh environments and heavy oil and gas value chains to pursue new business opportunities around the world. We have already demonstrated this through our acquisition of the oil sands position in Canada, the Peregrino field in Brazil, and the US shale gas position - all of which represent new challenges and opportunities for us to apply our technology and experience. For a description of these acquisitions see Section 3.2 Operational Review - International E&P.

We will continously seek to high grade our portfolio, for instance as we have done in our long term partnership with Sonatrach on Cove Point, and our acquisition of the remaining 50% of Peregrino and its operatorship. StatoilHydro's history as a national oil company (NOC) also gives us a competitive advantage in developing new cooperative models with other NOCs that are seeking partners for developing their resource bases.

Developing profitable midstream and downstream positions
StatoilHydro's ambition is to develop projects and production in oil and gas where we see attractive returns and value added to the upstream positions. Compared with many of our peers, we have a strong upstream focus in terms of our total value and asset base. Furthermore, we also have a sizeable mid- and downstream portfolio in relation to the marketing, trading, refining and storage of oil and gas products.

Creating a platform for new energy solutions and production
Our ambition in this area is to create a profitable business and to reduce emissions of greenhouse gases from our production. StatoilHydro is a leading industry player in carbon capture and storage. We are looking for opportunities for commercially sound investments in renewable energy, particularly in wind and sustainable biofuels, where we can exploit our offshore experience and fuel marketing know-how. We aim to build a portfolio of near-shore wind parks and develop technology for large scale offshore wind power generation.

Using exploration as a key enabler for value creation
Consistent with the strategies for maximising the long-term value of the NCS as well as building and delivering profitable international growth, StatoilHydro's ambition is to develop upstream projects and production in oil and gas where we see attractive returns, both in Norway and internationally. Our exploration strategy is key to this and is based on gaining access to high-potential basins globally and targeting multiple blocks in high-focus areas.

Our exploration strategy can be divided into three categories:

Frontier exploration aims at proving new fields in areas where the petroleum system remains unproven.

Growth exploration involves exploring for fields with stand-alone potential in areas where the petroleum system is known. We have a strong strategic focus on being an active operator with a view to shaping the future direction of our business.

Infrastructure-led exploration seeks to provide resources to existing infrastructure in a timely manner.

Using technological innovation and implementation as a key business enabler
StatoilHydro aims to build even stronger industry positions, and technology is a key enabler for achieving this goal and for realising our key strategies. The merger strengthened us significantly in the area of technology, providing us with a platform to further exploit our technical base. One example is the world class technology used on Troll and Gullfaks, where extended, multilateral and smart wells drain previously unrecoverable resources.

Our ambition is to attain distinctiveness and industrial leadership in six specific technologies:

- Exploration seismic imaging and interpretation
- Geophysical reservoir monitoring
- Oil sand reservoir characterization and recovery
- Intelligent drilling
- Subsea processing and long-range multiphase transport
- Carbon dioxide management

Technology makes a decisive contribution in all our activities, such as in field development in frontier deep waters, Arctic areas, heavy oil production, subsalt exploration, and environmental and climate issues. Our ambition is also to stay competitive in a broad range of core and emerging technologies along the energy provision value chain, including offshore wind and sustainable biofuel.

We aim to maintain the right course to capture future business opportunities and to develop smarter solutions to explore for and to produce energy in cost effective and environmentally friendly ways.

2.5 E&P Norway

2.5.1 Introduction

Exploration & Production Norway (EPN) consists of our exploration, field development and production operations on the NCS.

EPN is the operator of 42 developed fields that collectively produced more than three mmboe per day in 2008, which represented about 80% of the total production from the NCS. In 2008, our average daily oil and natural gas liquids (NGL) production was 824 mboe and our average daily gas production was 101.3 mmcm (37.1 bcf), totalling 1.461 mmboe per day.

We have ownership interests in exploration acreage throughout the licensed parts of the NCS, both within and outside our core production areas. We participate in 346 licences on the NCS and are an operator for 174 of them.

As of 31 December 2008, EPN had proved reserves of 1,396 mmbbl of crude oil and 498 bcm (17.58 tcf) of natural gas, which represents an aggregate of 4,529 mmboe.

2.5.2 Strategy

Several factors are expected to contribute to StatoilHydro's equity production on the NCS, including increased production and drilling efficiency, more cost-effective operations, and improved recovery from existing fields.

Other important measures include development of new discoveries, the proving of new resources through intensive exploration activity, increased access to new licences, enhanced focus on health, safety and the environment (HSE), and optimal use of existing infrastructure.

Our overall strategy on the NCS is defined as:

- Safe, efficient and reliable operations
- Capturing the full potential of the NCS in terms of developing profitable oil and gas resources

Maintaining current production level

As several fields on the NCS are maturing and production declines, high priority will be given to the implementation of measures to increase production from existing fields. The main measures in this context are more efficient drilling, increased regularity and improved oil recovery (IOR).

Higher regularity is expected to be achieved through improved well work, better reservoir management, de-bottlenecking of export infrastructure, improved planning of turnarounds and fewer topside plant failures.

Additional production is expected to be achieved by means of new capacity, including ramp-ups on Ormen Lange and Snøhvit, new field developments and implementation of IOR measures.

Tie-ins to existing infrastructure on fields that are in decline and/or have reached a critical point in their technical life will also have high priority. A well-balanced asset portfolio on the NCS with respect to regions and maturity is necessary to sustain total oil and gas production at current levels.

We need to achieve optimal development and exploitation of our existing portfolio in order to secure a solid foundation for future growth through continued high exploration activity. Active infrastructure-led exploration is a key factor in extending the life of the infrastructure in the tail-end production phase. However, access to new, prospective acreage is also necessary to maintain a high production level in the longer term.

One of our ambitions is to become one of the leading players in the Arctic by 2020. Considering the long lead times of field developments, a near-term opening of new acreage is imperative. Succeeding in new field developments in the northern areas of the NCS is a priority for StatoilHydro. Important efforts are currently underway to maintain stable operations in the Snøhvit LNG project, and to support a timely and robust development of the Goliat oil field. However, new high-quality exploration acreage remains a critical prerequisite for long-term success. To meet our ambitions in the northern area, we have to feasibly mitigate challenges in a range of areas - including geology and technology.

Gas position

The proportion of natural gas from our NCS portfolio is increasing. We have a flexible transportation system, with six different landing points on the European Continent / UK and flexibility in terms of gas deliveries from large gas producing fields such as Troll and Oseberg.

Safe and efficient operations are essential to our business

All activities in StatoilHydro are conducted with high focus on HSE in order to prevent harm to people and the environment. The implementation of Integrated Operations (IO) is expected to enhance economic value through higher production, higher regularity and cost reductions. Upgrading and modification programmes for offshore installations are also planned with a view to maintaining safe and efficient operations.

Our ongoing efforts to introduce one common operating model and common work processes on all our installations on the NCS, will enable us to utilize best practices, and optimise usage of our total resources to ensure safe and efficient operation.

Unit production costs on the NCS have been on a rising trend in recent years, in line with the industry development. StatoilHydro's management is implementing measures to contain future cost inflation.

The climate challenge

E&P Norway aims to maintain and strengthen the NCS's position as the most energy-efficient petroleum region in the world. We intend to push for energy efficiency in our daily operations and evaluate new field developments from a long term perspective with regard to energy and the environment. E&P Norway plans to also put more efforts into developing a more energy efficient supply chain with a life cycle perspective.

Industrial architect for NCS

We seek to maintain a stable relationship with suppliers, competitors, government and other stakeholders. The NCS is an arena for world-class innovation and technological development. StatoilHydro is a leader in the deployment of new technology, including drilling and subsea technology, new solutions for reducing costs and the use of new technology for developing discoveries. As the largest operator on the NCS, we are leaders in the development of optimal area solutions and the overall development of the NCS.

2.5.3 Key events in 2008

- Production increased by 3% from 2007 to 1461 mmboe/day.
- Kvitebjørn gas pipeline shut down as of August 2008.
- Turnaround at Snøhvit to enhance plant regularity.
- Offshore integration : Our Corporate Executive Committee (CEC) decided in December 2008 on a new operating model for our offshore organisation.
- High exploration activity: 27 discoveries out of 39 exploration wells.
- New projects sanctioned:
    - Yttergryta
    - Morvin
    - Norne M-template
    - Troll Field projects
    - Troll C Low pressure production project
- Production from seven new fields added a total capacity of approximately 70 mboe per day:
    - Volve
    - Gulltopp
    - Gamma Main Statfjord
    - Vigdis Øst
    - Theta Cook (Oseberg)
    - Oseberg Delta
    - Vilje
- Acquisitions: We aquired a 15% ownership interest in Goliat.

2.6 International E&P

2.6.1 Introduction

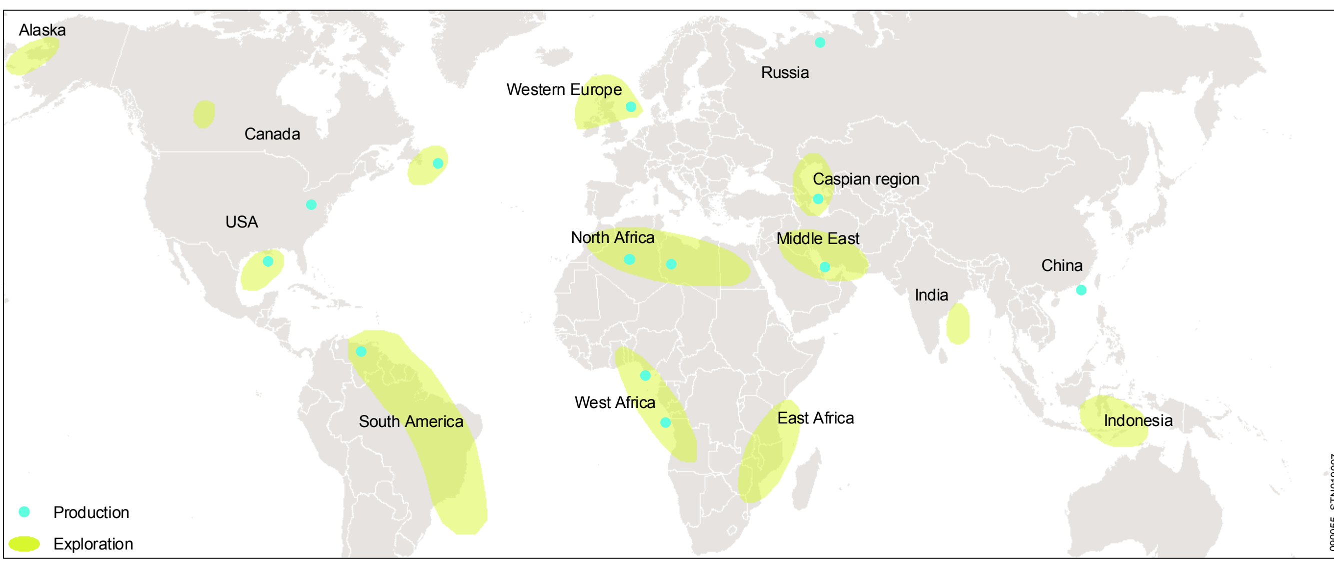
International Exploration & Production (INT) is responsible for exploration, development and production of oil and gas outside the Norwegian Continental Shelf. INT will provide a major part of StatoilHydro's future production growth.

In 2008 the business area had production from 12 countries: Canada, the USA, Venezuela, Algeria, Angola, Libya, Nigeria, UK, Azerbaijan, Russia, Iran and China. In 2008 INT produced 24% of StatoilHydro's total equity production of oil and gas, and INT's share is expected to increase significantly in the future.

We have exploration licences in North America (Canada and the USA), Latin America (Brazil, Cuba and Venezuela), Africa (Algeria, Angola, Egypt, Libya, Morocco, Mozambique, Nigeria and Tanzania), the European, Caspian and Russian area (Denmark, the Faroes, Ireland, the UK and Azerbaijan), and the Middle East and Asia (Iran, India and Indonesia).

The main sanctioned development projects in which we are involved are in Canada, the USA, Brazil, Angola and Ireland, and we believe we are well positioned for further growth through a substantial project portfolio that remains to be sanctioned.

The map shows our exploration and production areas.



2.6.2 Strategy

Our long-term upstream growth ambition will mainly be achieved by growing internationally. Growth is being pursued through our four focus areas - deep waters, harsh environments, gas value chains and heavy oil.

- **Deep waters** - we will further develop our position as a leading deepwater operator. Transfer of experience within subsea separation and water injection is expected to increase the final recovery factors significantly in some of the most challenging reservoirs in deepwater that we work with, such as in the Gulf of Mexico.

- **Harsh environments** - StatoilHydro has the ability to deliver cutting edge field developments in harsh conditions under the strictest environmental regulations. With 30 years of experience from development and operations offshore Norway, StatoilHydro has a competitive advantage on which to capitalise.

- **Gas value chains** - StatoilHydro has developed a comprehensive tool kit on gas value chains and demonstrated leading capabilities in the monetisation of major, often remote, gas resources. This experience will be a valuable contribution into future projects, such as Shtokman and Shah Deniz II, NnwaDoro and the major Marcellus shale gas accumulation.

- **Heavy oil** - we are well positioned through operatorships and ownership stakes in several key heavy oil projects. In the Peregrino field offshore Brazil and the Bressay and Mariner fields offshore UK we will draw upon our experience from the North Sea. For our large, long term resource base in Canadian oil sands we will draw on our experience from our involvement in the subsurface aspects of the Venezuelan Sincor project. The development will take advantage of technological advances deriving from the research and development efforts performed at the StatoilHydro heavy oil technology centre in Canada.

These focus areas all draw upon our existing strong technical and project execution skills acquired through our experience from the NCS. We access new resources through advanced exploration activities, focused business development and long-term partnerships with national oil companies.

Our international access strategy has increased the scale of our operations in terms of produced volumes, reserves and technological and geographical breadth. We aim to build a robust, diverse and long-life portfolio with significant optionality and flexibility.

INT's near-term focus is on delivering on the production targets for 2012 communicated to the financial markets. Recent acquisitions have also given us significant operatorships that are in the exploration and planning phases, as well as the major Peregrino development project.

Major efforts are being made on making the transition from being a mainly North Sea player towards becoming a world class international operator. Over the last few years, StatoilHydro has built up a large resource base. We are working continuously to develop our inventory of projects into producing assets by looking at innovative technical and commercial solutions.

2.6.3 Key events in 2008

- Equity production increased by 10% from 2007 to 465 mmboe/day.
- High Exploration activity, eight discoveries out of 40 exploration wells in 2008, with several interesting discoveries in Algeria, Angola, UK and the Gulf of Mexico.
- PSVM development in Block 31 in Angola was sanctioned by Sonangol on 28 July 2008.
- Production from four new fields added a total capacity of approximately 100 mboe per day:
  - Mondo in Angola
  - Saxi Batuque in Angola
  - Agbami in Nigeria
  - ACG phase 3 in Azerbaijan

- Acquisitions:
  - We have made a strategically important entry into unconventional gas through the acquisition of a 32.5% interest in Chesapeake's Marcellus shale gas acreage in the Appalachian region in the USA.
  - Our position as an international operator has been strengthened through handover of project responsibility for the Peregrino development offshore Brazil, following the acquisition of the remaining 50% interest in this field.

2.7 Natural Gas

2.7.1 Introduction

The Natural Gas (NG) business area is responsible for StatoilHydro's transportation, processing and marketing of pipeline gas and LNG worldwide, including the development of additional processing, transportation and storage capacity.

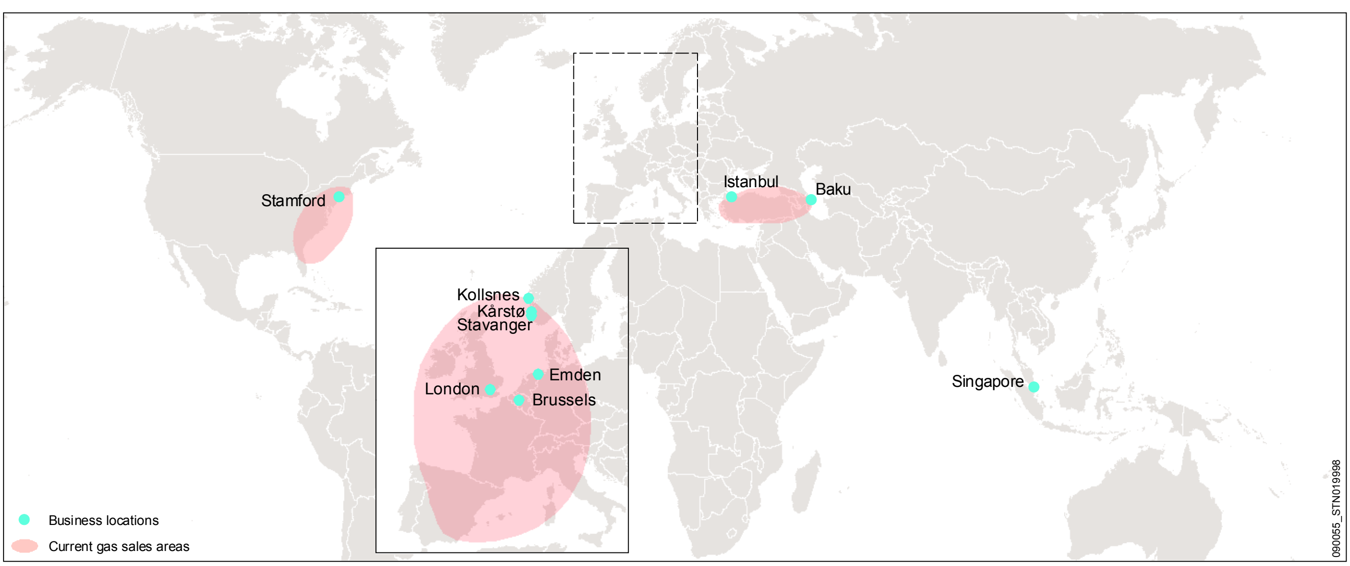
NG is responsible for marketing gas supplies originating from the Norwegian State's direct financial interest (SDFI). In total, we account for approximately 80% of all Norwegian gas exports and are responsible for technical operation of the majority of export pipelines and onshore plants in the processing and transportation systems for Norwegian gas (Gassled).

NG's business is conducted from three locations in Norway (Stavanger, Kårstø and Kollsnes) and from offices in Belgium, the UK, Germany, Turkey, Singapore, Azerbaijan and the US.

In 2008, we sold 37.0 bcm (1.31 tcf) of natural gas from the NCS on our own behalf, in addition to approximately 32.0 bcm (1.13 tcf) NCS gas on behalf of the Norwegian State. StatoilHydro's total European gas sales, including third party gas, were 76.8 bcm (2.71 tcf) in 2008. That makes us the second largest gas supplier in Europe with a market share of around 15% in the European gas market.

From our international positions (mainly Azerbaijan and the US), we sold 4.1 bcm (0.4 tcf) of gas in 2008, of which 2.3 bcm (0.1 tcf) was entitlement gas.

We have a significant interest in the NCS pipeline system owned by Gassled, which is the world's largest offshore gas pipeline transportation system, totalling approximately 7800 kilometres. This network links gas fields on the NCS with processing plants on the Norwegian mainland, as well as terminals at six landing points located in France, Germany, Belgium and the United Kingdom, providing us with flexible access to customers throughout Europe.



2.7.2 Strategy

NG's strategy is to maximise the value of our long-term sales business, improve our portfolio optimisation activities and establish new gas value chains.

We have a large long-term gas sales contract portfolio and are continuously evaluating midstream and downstream opportunities in order to take further advantage of our existing infrastructure, access to supplies and experience in marketing of natural gas. Our downstream strategies may differ from region to region depending on our particular position in the area and the nature of the market in question.

In Europe, we endeavour to achieve greater efficiency from our existing supply portfolio, to update and refine our commercial relationships with key customers and to establish new positions that will improve the flexibility of our operations. Through balancing, optimisation and trading activities, we plan to continue to create additional value on top of our long-term sales business.

Natural gas is the focus of many exploration and business development activities carried out by both INT and EPN. A large proportion of the exploration activities on the NCS are focused on gas, and a number of INT projects focus on accessing international gas reserves.

StatoilHydro aims to further develop its position on the NCS and internationally through increased production and investments in new fields and infrastructure aimed at serving the European and US gas markets. NG plans to strengthen established market positions in Europe with gas from the NCS, the Caspian Sea and North Africa. We plan to further develop the market position at the Cove Point terminal on the East Coast of the US. Our aquisition of a 32.5% share in the Marcellus gas deposit in the Appalachian basin is expected to significantly strengthen our US natural gas business in terms of production, reserves and marketing.

The main objective of NG's strategy is to improve our growth opportunities in all parts of the natural gas business and fully exploit the opportunities that changing market conditions provide us. This means increased focus on extracting value from the existing contracts and asset portfolio and increasing the value added from trading and optimisation activities beyond the landing point. It also entails increased internationalisation of the gas business, including activities in North America, LNG growth and the addition of new markets.

The main task for NG is to maximise value creation in markets that are constantly changing and deregulating, particularly Europe, making active use of the new opportunities offered and managing risks within acceptable parameters.

A necessary lever to support this strategy is to continue to develop, maintain and operate the upstream and midstream (transport and processing) infrastructure required to safely and reliably deliver gas volumes where and when required. Efforts aimed at ensuring the safety, integrity and regularity of the infrastructure, while simultaneously upgrading and expanding the existing processing plants at Kårstø and Kollsnes is expected to be of key importance in Norway.

2.7.3 Key events in 2008

- Record gas sales at record prices. In 2008 we sold 39.3 bcm entitlement gas, approximately 10% increase from 2007. The European piped gas price increased by 42% from 2007 to 240 øre/sm3 in 2008.
- The Chesapeake agreement is a major building block in StatoilHydro's US gas value chain. The company gets access to reserves produced close to the highest paying market in the US and is building on our existing Cove Point LNG position and our well-established gas marketing and trading organisation.
- An agreement to join Swiss EGL Group was signed 13 February to establish a joint venture to develop, build and operate the Trans Adriatic Pipeline (TAP) potentially supplying the European market with gas from the Caspian Sea and Middle East regions. A final investment decision is linked to the Shah Deniz Stage 2 development.
- Diversion of LNG cargoes. For the first time, we sold a cargo of Liquefied Natural Gas (LNG) from the Snøhvit field to Japan. The vessel arrived at the Ohgishima terminal in Tokyo Bay on 22 March. Price differences between continents give us added value by diverting LNG cargoes to the most profitable markets. Eight Snøhvit cargoes originally destined for Cove Point were diverted to other locations in 2008.

2.8 Manufacturing and Marketing

2.8.1 Introduction

Manufacturing & Marketing (M&M) adds value through the processing and sale of the group's and the Norwegian State's production of crude oil and natural gas liquids (NGL).

M&M is responsible for the group's combined operations in the transportation of oil, processing, the sale of crude oil and refined products, retail activities and marketing of natural gas in Scandinavia. We operate in approximately 12 countries, have two refineries, one methanol plant and two crude oil terminals, and have international trading activities and an extensive distribution network for businesses and private customers. Over one million customers visit our approximately 2100 service stations daily.

More than 13,000 people representing over 30 nationalities are employed by M&M. Approximately 10,500 of them work outside Norway. In 2008, we had trading activity of 717 mmbbl of crude oil and condensate, approximately 30 million tonnes of refined oil products and 11.8 million tonnes of NGL. The refinery throughput was 15.2 million tonnes. In the energy and retail market, we sold approximately 13 billion litres in 2008, including eight billion litres of petrol and diesel.

2.8.2 Strategy

M&M's strategy is to contribute to the integrated oil value chain by selectively building competitive midstream and downstream positions.

This strategy aims to maximise value of our crude oil production and to strengthen and support the value of the group's upstream portfolio. Continued focus on safe, reliable and efficient operations is the basis for future growth in this segment. We will focus on further developing our position in North America to maximise the value creation from the group's crude production in the Gulf of Mexico, future production of extra heavy oil from Canada and Brazil, as well as our production imported to North America from other regions.

Oil Sales, trading and supply (OTS)

OTS will continue strengthening our global trading position for crude and natural gas liquids, with increased presence and activity in selected regions as well as sustaining our market position in North West Europe. StatoilHydro equity production is the backbone of our business and growth ambitions, and we will focus strongly on delivering business development and infrastructure projects to secure market access and competitive pricing for our equity volumes world wide. Physical trading infrastructure and solid logistical solutions will form the competitive edge for our business. We will increase flexibility in marketing of NCS volumes and also evaluate infrastructure assets independently of our own equity production to support increased trading activity.

Manufacturing
Main focus for our manufacturing activity is to contribute to maximising the value of StatoilHydro's feedstocks from field to end user and to be an active downstream partner in the internationalisation of StatoilHydro.

Our ambition is to maintain the competitiveness of Mongstad, Kalundborg and Pernis by exploiting technology in order to improve reliability, energy efficiency, maintenance and HSE performance. Our focus will be to increase the robustness of the sites, whilst adapting to changes in feedstock and market variations. Such changes may well include the increased upgrading of gasoils and heavy oils to diesel, and production and supply of Biofuels. The new combined heat and power (CHP) unit at Mongstad will improve energy efficiency when it starts up in 2010, and also lay a foundation for future improvements.

We will implement cost efficient and flexible liquid transportation solutions. The logistics solution will add value by allowing the possibility to combine cargoes and crude qualities, to enable a reduction in refinery feedstock costs and give flexibility to handle high tan and heavy crude oil. It will also be important to develop business concepts and related technology that are feasible across the Arctic area.

Energy and retail
Our energy and retail business will be increasingly focused on the transportation fuel sector, as we expect the stationary energy sector to gradually replace oil with other non carbon-based energy carriers.

Our ambition is to consolidate our downstream positions in Scandinavia, focusing on increasing profitability and establishing StatoilHydro as a leading supplier of bio fuels in selected markets. In Eastern Europe, we plan to build on our strong Baltic and Polish positions, and continue to evaluate market opportunities based on the Scandinavian marketing concept.

2.8.3 Key events in 2008

M&M experienced a challenging trading market in 2008, but were well positioned to cope with the unprecedented market conditions and volatile crude oil prices. These are the key events of 2008.

- We experienced a challenging trading market during 2008, due to the extreme unpredictability of crude oil prices and the oil products markets.
- Increased diesel production capacity at Kalundborg refinery in Denmark after start up of the modified fuel oil conversion unit in March 2008.
- Reduced emissions to air at Mongstad when the volatile organic compounds (VOC) recovery unit went on stream on 13 June 2008.
- Our largest ever turnaround (shut-down for inspection and maintenance) took place at the Mongstad refinery from September to November 2008.
- Major on-going restructuring in Sweden, where we have converted 82 manned stations to unmanned and closed down 251 stations
- Acquisitions:
  - Our energy and retail business received approval from the European Commission for the acquisition of 274 JET stations in Scandinavia on 21 October 2008.

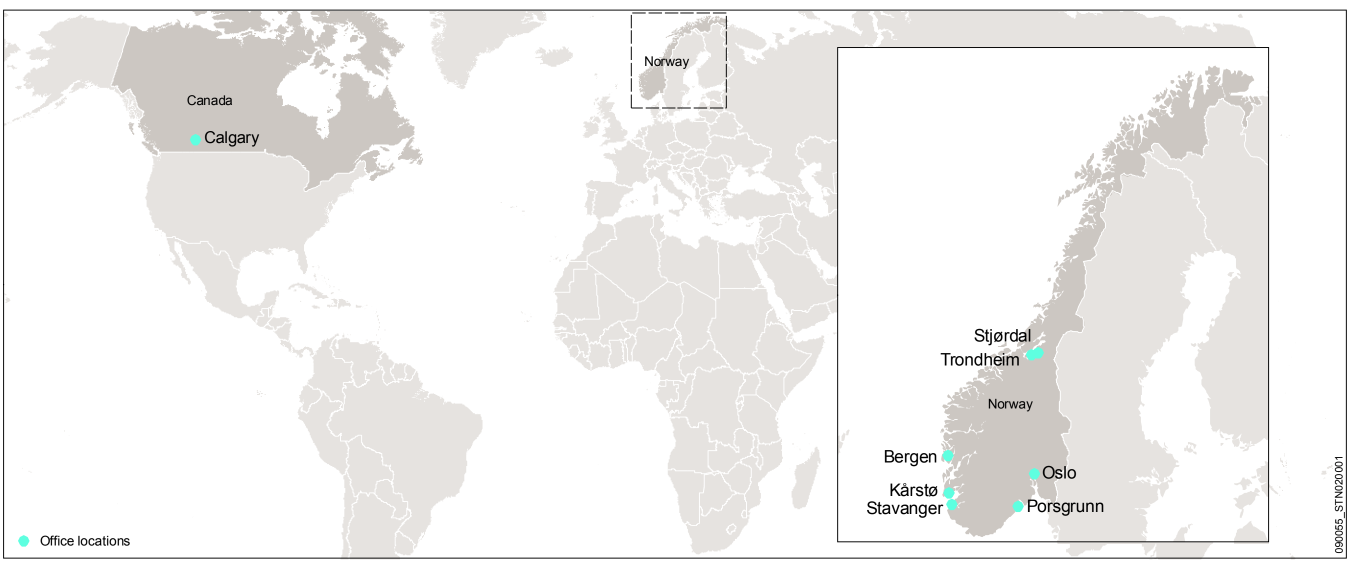
2.9 Technology and New Energy

2.9.1 Introduction

Technology & New Energy (TNE) is responsible for the development of technology and renewable energy contributing to global business success.

This means that TNE is responsible for ensuring capacity and competence in the field of technology, in addition to creating distinct technological solutions for global growth. This includes delivering innovative and competitive technological solutions for exploration, increased recovery, field development, and safe, efficient and environmentally-friendly operations. The research and development department, which has research centres in Trondheim, Bergen and Porsgrunn in Norway and in Calgary in Canada, is engaged in research and development, piloting, implementation and commercialisation of new technology.

Climate change, security of supply and a growing demand for clean energy are opening up new business opportunities. StatoilHydro is in a position to seize these opportunities by utilising long-standing core capabilities from the oil and gas industry. StatoilHydro's New Energy business unit is responsible for the company's business effort within renewable energy. The activities are grouped under renewable energy production, sustainable fuels, carbon dioxide management and technology development.



2.9.2 Strategy

StatoilHydro's technology strategy focuses on generating long-term business value through identifying, developing and applying technologies that will secure the company's long term position as an internationally competitive organization.

Technology strategy

StatoilHydro's strategy is to maximise value as an upstream oriented, technology based energy company. The objectives of the corporate technology strategy are to: (i) identify those technologies that will help the company to develop as a profitable, performance-driven, internationally competitive organization; and (ii) guide its future growth in certain areas that can lead to substantial technology differentiation.

The strategy is therefore focused on generating long-term business value through leading technology application. Its realization will demand a response from the entire technical community to increase the value of existing business, secure and develop platforms for further growth, and operate in new and more challenging environments. The strategy is upstream-motivated, although some weight is placed on energy diversification. Operational excellence and industry-leading HSE performance underpin all activities.

The corporate technology strategy is driven by the central 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 (for example, the Gulf of Mexico and Brazil) 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, such as offshore wind and sustainable biofuels.

Furthermore, IOR and improved drilling and well solutions are important to successfully growing our business. StatoilHydro 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 forthcoming Improved oil recovery (IOR) ambitions on the NCS and internationally. Drilling and well technology plays a key role in increasing production and ensuring regular delivery, and through its application we intend to achieve faster operations, reduced downtime, and improved well flow whilst improving safety during operations. Supplier cooperation and venture activities will remain important. We are also reviewing our intellectual property rights policy and clarifying our policy on technology acquisition in terms of proprietary development and cooperation as opposed to off-the-shelf purchasing.

Although the selected technologies are dealt with separately, it is important to note that leading industrial solutions depend on their successful *combination*.

New Energy
To StatoilHydro, climate change is both a challenge and a business opportunity. Our focus is on building a business with significant economic value creation in the short and long term, with particular emphasis on offshore wind, sustainable bio-fuels and CO_2 management. However, with the new energy industry still being in an early phase of development it difficult to "pick all the winners" of the future, so we are developing additional options in selected areas. We also believe that our involvement has the potential to add value to certain oil and gas activities within the company, particularly within CO_2 management.

2.9.3 Key events in 2008

Technology
- The world's first remote operated hot tap system was successfully completed, connecting Tampen Link and SIPS (Statfjord Interfield Pipeline System)
- Production and sub surface support centres were established
- The first test of Drilltronics, an early version of automated drilling, was successfully completed on Statfjord C in the first quarter of 2008.

New Energy
- The UK government gave consent to develop our 88-turbine Sheringham Shoal offshore wind park
- We invested in Brightsource Energy, a company developing concentrated solar thermal technology
- New projects sanctioned:
  - Hywind, the world's first full scale floating offshore wind turbine was sanctioned and is now under construction.
  - We entered into the Icelandic Deep Drilling Project for deep geothermal energy.

2.10 Projects

2.10.1 Introduction

Projects (PRO) is responsible for planning and executing all major development and modification projects , as well as project and operational procurement, including securing rig capacity based on a corporate rig strategy.

Our goal is to be world-class in terms of project execution and to deliver on time and within budget, in accordance with high HSE standards and agreed quality standards. To become a truly global energy player, it is essential that StatoilHydro is able to execute projects at the very highest level, and thereby strengthen the company's international competitiveness.

Our current portfolio consists of more than 120 modification and development projects in the execution phase, with an expected total investment cost of more than NOK 200 billion. A major part of the portfolio consists of activities related to ongoing redevelopment efforts, aimed at maximising production from the NCS.

2.10.2 Strategy

Our strategy is to develop high quality projects as planned and in a safe and reliable manner.

Our ability to utilise the company's world-leading technology, execute projects in complex surroundings and demonstrate our core expertise in new markets is of vital importance for opening up new business opportunities. The fight for global resources is fierce, but familiar to StatoilHydro. The real challenge is inflicted by local market, local practices, new standards and new cultures. These unfamiliar settings impact price, availability, quality and lead times for deliveries.

We have a growing portfolio of international projects, such as the In Salah gas compression project in Algeria, the development of the Iranian gas field South Pars phases 6, 7 and 8 and the Leismer demonstration project for heavy oil recovery in Canada - as well as the major heavy oil project offshore Brazil, Peregrino, which is 100% StatoilHydro owned and operated.

On the NCS, there is a growing need for the redevelopment of existing fields and installations. As fields mature, production equipment needs upgrading. In the years ahead, an increasing number of fields will need upgrading or renewal of drilling units, control systems, hydrocarbon processing systems, cranes and other major redevelopment efforts.

Developing sustainable solutions for clean renewable energy with a sound financial rationale is a key element in the group's strategy. We anticipate an increased focus on new energy projects in the years to come. In this context, the pre-sanctioning of two offshore wind projects, namely Hywind and Sheringham Shoal, serves as important milestones for PRO in 2008.

In order to handle our projects in the most efficient way, we intend to use inter-field project organisations to standardise tasks and continuously search for synergies between projects and contracts.

We are dependent on the cooperation of a highly professional supply industry. Therefore we seek to secure a high degree of diversity among our suppliers, and are continuously on the lookout for innovative solutions and access to the best qualified expertise and external resources.

Securing sufficient flexibility in changing market conditions is a key focus area and we expect our suppliers to adjust accordingly. We have seen increasing expenditure in the recent past but in the current worldwide economic situation, the time has come to optimize cost while improving quality, productivity and efficiency in collaboration with our suppliers. As an outcome, we expect that supplier costs will be reduced going forward.

2.10.3 Key events in 2008

- The operatorship for the Peregrino development offshore Brazil was handed over from Anadarko to StatoilHydro on 2 June.
- Oseberg Delta started production on 30 June.
- Production from the first platform on the South Pars field (SPD9) was started on 24 August. The second platform (SPD7) started production on 21 December.
- The new Kollsnes Flash Gas and Compressor facilities commenced operation just before year end.
- The Site Safety initiative, a cooperation between the leading advisors construction management and HSE management, was launched.
- Through its strategic and operational sectors, Procurement has contributed to a successful "all time high" operation of 17 mobile drilling units in parallel on the NCS.
- Drilling rigs and associated services were secured in 2008 for new prospects in UK, Ireland, Canada and Libya.

3 Operational review

3.1 E&P Norway

3.1.1 Industry overview

While oil production on the NCS shows a falling trend, improved oil recovery will fight the decline. Production of natural gas is expected to increase and constitute a larger share of total production in the future.

In 2008 the total production from the NCS was 4.16 mmboe per day. Improved oil recovery from existing fields is an important factor in maintaining the current production level, and most of the IOR activities are related to the drilling of new wells. Natural gas production is increasing and we expect production of natural gas to constitute a larger share of total production in the future.

A major challenge for the industry has been to secure rig capacity, which is vital to increasing the recovery factor. A tight supplier market on the back of recent years' oil price increases has put upward pressure on rig rates, as well as overall oil service expenses.

The global financial crisis that escalated in September will probably have an impact on this situation. However, much of the rig fleet is on longer term contracts, so a considerable change is not likely to be seen before 2010 or 2011. The recent turmoil in the financial and commodity markets has sharpened the focus on capital efficiency and cost control. Investment plans have been prioritized, and our portfolio of field projects and exploration prospects has been trimmed and high graded. However, short-term IOR efforts are fairly robust.
Another challenge facing the companies on the NCS is that future production is expected to come from smaller and more complicated fields. New field development projects typically have more complex reservoirs and are technically more challenging than before. They will therefore demand more resources per barrel than the older and larger fields. As the NCS matures, the investment level is expected to remain at a high level.

We believe there is still a large undiscovered resource potential on the NCS, both in mature and frontier areas. According to estimates published by the Norwegian Petroleum Directorate, approximately one-third of the resources on the NCS are undiscovered. Existing infrastructure ensures profitability for small discoveries in mature areas that would not otherwise justify a stand alone development. The majority of the remaining large discoveries are expected to be located in the frontier areas.

Access to attractive acreage is an important factor in realising the potential of the NCS. In January 2009, 40 companies were awarded 34 new licences in the North Sea, the Norwegian Sea and the Barents Sea through Awards in Predefined Areas(APA) 2009. The annual APA concession system offers previously relinquished acreage and unawarded blocks offered in previous licensing rounds located in specific mature parts of the NCS. The APA system ensures that large areas close to existing and planned infrastructure are made available to the industry, and the APA area will be expanded as new exploration areas are matured.

The deadline for applications in the 20th licensing round expired on 7 November 2008 with a total of 46 companies submitting applications. According to a press release from the Norwegian Petroleum Directorate, this was one of the largest licensing rounds ever, and the oil companies' interest demonstrated "that new exploration areas on the Norwegian Shelf are competitive in an international perspective." Awards are planned for March/April 2009.

Ensuring safe and stable operation with no harm to people or the environment is an essential aspect of operating on the NCS, and there has been increased focus on this issue in recent years.

3.1.2 The NCS portfolio

3.1.2.1 Core production areas

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

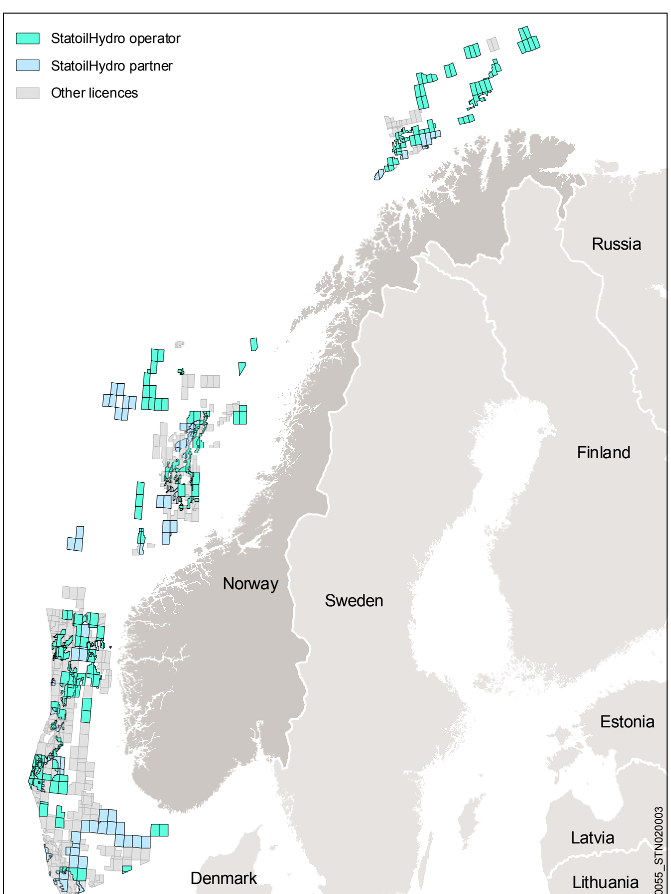
We have organised our production operations into four business clusters - Operations West, Operations North Sea, Operations North and Partner Operated Fields.

The fields in each area use common infrastructure, such as production installations and oil and gas transport facilities where possible. This reduces the investment required to develop new fields. Our efforts in these core areas will also focus on finding and developing smaller fields through the use of existing infrastructure and on increasing production by improving the recovery factor.

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

3.1.2.2 Potential producing areas

In addition to the producing areas, we operate a significant number of exploration licenses. The exploration acreage is located both in undeveloped frontier areas as well as close to infrastructure and producing fields.



North Sea. The total licensed acreage in the North Sea covers 74,841 square kilometres. We operate 21,318 square kilometres and are partner in 12,229 square kilometres. Following the execution of work programme and prospectivity evaluation, one licence has been relinquished in the North Sea in 2008. In addition, six licences were partly relinquished and two licences were relinquished through farm-out in 2008. Three licences were awarded to us in the Awards in Predefined Areas 2007 (APA 2007) and we became operator of two of these. In addition, one licence was awarded as licence extension. Four licenses were awarded to us in the Awards in Predefined Areas 2008 (APA 2008) and we became operator of two of these.

Norwegian Sea. Total licensed acreage in the Norwegian Sea covers 37,033 square kilometres. We operate 13,587 square kilometres and are partner in 7,384 square kilometres. In the deepwater region we have interests in licences covering approximately 10,000 square kilometres. Following execution of work programme and prospectivity evaluation, six licences were relinquished in the Norwegian Sea in 2008; three in the deep water region and three in the shallow water region. In addition, four licences were partly relinquished in 2008. Four licences were awarded to us in the APA 2007, and we became operator of all of these. In addition, we acquired one new licence through farm-in in 2008. Two licenses were awarded to us in the Awards in Predefined Areas 2008 (APA 2008) and we became operator of one of these. In addition, two licenses were awarded as license extensions.

Barents Sea. Total licensed acreage in the Barents Sea covers 17,710 square kilometres. We operate 13,348 square kilometres and are partners for 1,698 square kilometres. Following execution of work programmes and prospectivity evaluation, one licence has been relinquished in the Barents Sea in 2008. In addition two licences were partly relinquished in 2008. Three licences were awarded to us in the APA 2007, and we became operator of one of these. In addition, one licence was awarded as a licence extension.

3.1.2.3 Portfolio management

Through active portfolio management we seek to optimise our licence portfolio, and strengthen our core areas.

During 2008, we signed a sales and purchase agreement to aquire Det Norske's 15% share in Goliat in the Barents Sea and a swap involving a 10% share of Det Norske's participating interest in the Ragnarrock discovery on the Utsira Height in exchange for interests in two exploration licences in the Grane and Heimdal areas. Furthermore, several exploration licence transactions have been performed.

3.1.3 Exploration

StatoilHydro has delivered an extensive exploration programme on the NCS in 2008. We participated in 39 exploration wells, resulting in 27 discoveries. This implies a success rate approaching 70%.

We operated 34 of the 39 exploration wells including 24 of the 27 discoveries. In addition, we operated nine exploration extensions where six resulted in discoveries.

The most important discoveries in 2008 were Dagny/Ermintrude (PL048/PL303) near Sleipner in the North Sea which has opened a new oil play in a mature gas province, and Snefrid South and Haklang (PL218) near the Luva discovery in the Norwegian Sea that could provide the basis for new gas infrastructure. The five wildcat exploration wells completed in the Barents Sea were all discoveries. Although the proven volumes in these wells have not met our most optimistic expectations, they have enhanced our understanding of the hydrocarbon potential in the area and will be important guides for our continued exploration activity in the Barents Sea. Nearly half of the discoveries proven in 2008 are located near existing infrastructure and are of small to medium size. These discoveries are critical to maximise the take-out in and around existing fields and most of them already have a planned tie-back solution.

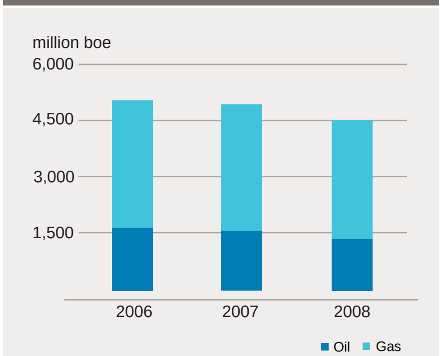
The table below shows our exploration and development wells drilled on the NCS during the last three years.

Exploration and development wells drilled on the NCS	2008	2007	2006
North Sea			
StatoilHydro operated exploratory	**13**	11	5
Successful	**8**	9	3
Dry	**5**	2	2
StatoilHydro operated development	**75**	87	53
Partner operated exploratory	**4**	0	2
Successful	**2**	0	0
Dry	**2**	0	2
Partner operated development	**13**	16	15
Norwegian Sea			
StatoilHydro operated exploratory	**14**	6	5
Successful	**11**	3	2
Dry	**3**	3	3
StatoilHydro operated development	**13**	12	17
Partner operated exploratory	**1**	3	0
Successful	**1**	1	0
Dry	**0**	2	0
Partner operated development	**3**	2	2
Barents Sea			
StatoilHydro operated exploratory	**7**	3	2
Successful	**5**	2	1
Dry	**2**	1	1
StatoilHydro operated development	**0**	0	2
Partner operated exploratory	**0**	1	4
Successful	**0**	1	2
Dry	**0**	0	2
Partner operated development	**0**	0	0
Totals			
Exploratory	**39**	24	18
Successful	**27**	16	8
Dry	**12**	8	10
Development	**104**	117	89

3.1.4 Oil and gas reserves

forAt the end of 2008, we had a total of 1396 mmbbl of proved oil reserves and 498 bcm (17.6 tcf) of proved natural gas reserves on the NCS.

OIL AND GAS RESERVES



Measured in barrels of oil equivalent (boe), our proved reserves consist of 31% oil and 69% natural gas, based on total proved reserves on the NCS of 4529 mmboe.

The following table shows our proved reserves of NCS crude oil and natural gas as of the end of the periods indicated. The data is net of royalties in kind, but includes reserves attributable to our account based on our proportionate participation in fields with multiple participants. No major discoveries or other favourable or adverse events have occurred since 31 December 2008 that would mean a significant change in the estimated proved reserves as of that date.

Further information on reserves can be found in note 34 - Supplementary oil and gas information - to our Consolidated Financial Statements.

Year		Oil/NGL mmbbls	Natural gas bcm	bcf	Total mmboe
2008	Proved reserves end of year	**1,396**	**498**	**17,581**	**4,529**
	of which, proved developed reserves	**1,113**	**410**	**14,482**	**3,693**
2007	Proved reserves end of year	1,604	535	18,893	4,971
	of which, proved developed reserves	1,187	427	15,084	3,875
2006	Proved reserves end of year	1,667	541	19,129	5,068
	of which, proved developed reserves	1,188	379	13,378	3,566

3.1.5 Production

In 2008, our total equity oil and NGL production in Norway was 302 mmbbl, and gas production was 37.1 bcm (1310 bcf), which represents an aggregate of 1.461 mmboe per day.

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

Area	StatoilHydro's equity interest in % [1]	Operator	On stream	License expiry date	Producing wells Oil	Producing wells Gas	Average daily production in 2008 mboe/day
Operations North Sea							
Sleipner Øst	59.60	StatoilHydro	1993	2028		14	44.4
Sleipner Vest	58.35	StatoilHydro	1996	2028		17	91.0
Gungne	62.00	StatoilHydro	1996	2028		4	14.5
Loke	50.00	StatoilHydro	2008	2018		1	0.1
Troll Phase 1 (Gas)	30.58	StatoilHydro	1996	2030		39	149.3
Troll Phase 2 (Oil)	30.58	StatoilHydro	1995	2030	106		43.9
Fram	45.00	StatoilHydro	2003	2024	9		27.9
Kvitebjørn	58.55	StatoilHydro	2004	2031		8	47.8
Visund	53.20	StatoilHydro	1999	2023	6	1	24.2
Grane	38.00	StatoilHydro	2003	2030	24		65.3
Veslefrikk	18.00	StatoilHydro	1989	2015	18		2.3
Huldra	19.88	StatoilHydro	2001	2015	0	5	4.8
Glitne	58.90	StatoilHydro	2001	2013	7		5.2
Heimdal	29.87	StatoilHydro	1985	2021 [2]		6	1.0
Brage	32.70	StatoilHydro	1993	2017 [3]	22		11.4
Vale/Vilje	28.85	StatoilHydro	2002	2021		1	4.6
Volve	59.60	StatoilHydro	2008	2028	2		20.7
Total Operation North Sea					194	96	558.4
Operations West							
Statfjord Unit	44.34	StatoilHydro	1979	2026	82	2	72.7
Statfjord Nord	21.88	StatoilHydro	1995	2026	4		3.0
Statfjord Øst	31.69	StatoilHydro	1994	2026 [4]	5		4.9
Sygna	30.71	StatoilHydro	2000	2026 [5]	2		1.6
Gullfaks	70.00	StatoilHydro	1986	2016	104	9	163.3
Snorre	33.32	StatoilHydro	1992	2015 [6]	37		50.5
Tordis area	41.50	StatoilHydro	1994	2024	5		11.5
Vigdis area	41.50	StatoilHydro	1997	2024	10		24.0
Gimle	65.13	StatoilHydro	2006		1		6.8
Oseberg	49.30	StatoilHydro	1988	2031	59		125.9
Tune	50.00	StatoilHydro	2002	2032		4	12.4
Total Operations West					309	15	476.6
Operations North							
Kristin [7]	55.30	StatoilHydro	2005	2033 [8]	12		92.4
Norne	39.10	StatoilHydro	1997	2026	12		26.0
Urd	63.95	StatoilHydro	2005	2026	5		5.8
Heidrun	12.41	StatoilHydro	1995	2024	34		13.8
Åsgard	34.57	StatoilHydro	1999	2027		37	124.8
Mikkel	43.97	StatoilHydro	2003	2022 [9]		3	21.0
Njord	20.00	StatoilHydro	1997	2021 [10]	8		12.9
Snøhvit	33.53	StatoilHydro	2007	2035		6	17.1
Total Operations North					59	46	313.8
Partner Operated Fields							
Ormen Lange	28.92	Shell	2007	2041		6	61.5
Ekofisk area	7.60	ConocoPhillips	1971	2028	152		26.2
Ringhorne Øst	14.82	ExxonMobil	2006	2030	3		5.1
Sigyn	60.00	ExxonMobil	2002	2018	1	2	15.8
Enoch	11.78	Talisman	2007	2018	1		0.8
Skirne	10.00	Total	2004	2025		2	2.4
Murchison (Norw. Part)	11.52	CNR	1980	2026			0.1
Total Parter Operated Fields					157	10	111.9
Total					719	167	1,460.8

1) Equity interest as at 31 December 2008.

2) PL036 expires in 2021 and PL102 expires in 2025. The owner share of the topside facilities is 39.44%, however the owner share of the reservoir and production is 29.87%.

3) PL185 expires in 2015 and PL053B and PL055 both expire in 2017.

4) PL037 expires in 2026 and PL089 expires in 2024.

5) PL037 expires in 2026 and PL089 expires in 2024.

6) PL089 expires in 2024 and PL057 expires in 2015.

7) Kristin equity reflects inclusion of Tofte reservoir.

8) PL134B expires in 2027 and PL199 expires in 2033.

9) PL092 expires in 2020 and PL121 expires in 2022.

10) PL107 expires in 2021 and PL132 expires in 2024.

The following table shows our average daily equity production of oil, including NGL and condensates, and natural gas for each of the years ending 31 December 2008, 2007 and 2006.

	For the year ended 31 December								
	2008			2007			2006		
Area production	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe
Operations North	**175**	**22**	**314**	181	19	303	182	16	281
Operations North Sea	**250**	**49**	**558**	236	56	590	262	59	634
Operations West	**355**	**19**	**477**	362	16	464	379	20	503
Partner operated fields	**43**	**11**	**112**	39	3	60	41	2	56
Total	**824**	**101**	**1,461**	818	95	1,417	864	97	1,474

3.1.6 Development

3.1.6.1 Fields under development

The following fields are currently under development on the Norwegian Continental Shelf.

The **Alve** field, in which we hold an 85% interest, is located in PL159B in the Norwegian Sea, 14 kilometres south west of the Norne field. The PDO was submitted to the Norwegian authorities in January 2007 and approved in March 2007. The field will be developed through the installation of a four-slot subsea wellhead template that will be tied back to the Norne Floating Production Storage Offloading (FPSO). Production is scheduled to start in early 2009. The total investment for the project is estimated to be NOK 2.7 billion. Production commenced on 19 March, 2009.

Gjøa is located in the North Sea and will be developed by installing a subsea production system and a semi-submersible production platform. Gas will be exported via FLAGS pipeline to St. Fergus and oil export through the Troll 2 pipeline to the StatoilHydro-operated Mongstad refinery near Bergen. The Gjøa platform will process and export volumes from both the Gjøa field and the neighbouring Vega fields. The platform will be supplied with land-based electricity from Mongstad. The total investments are estimated to be NOK 31.2 billion. We hold a 20% interest in Gjøa. Production is scheduled to start in late 2010.

Morvin, in which we hold an interest of 64%, is an oil and gas field located in the Norwegian Sea, 15 kilometres north-west of Åsgard. The field was discovered in 2001 and the Plan for Development and Operation was submitted in February 2008 and approved by the Norwegian authorities in April 2008. The field will be a subsea development with two templates tied in to Åsgard B for processing through a 20 kilometres long wellstream pipeline. The development of Morvin is currently estimated to require capital expenditure of NOK 9 billion, and production from the field is estimated to commence in late 2010.

The PDO for **Skarv** was submitted in June 2007 and approved by the Norwegian Parliament in December 2007. Skarv is an oil and gas field located in the Norwegian Sea, in which we have an interest of 36.165% and for which BP is the operator. Skarv extends across three production licences (PL212/262 Skarv and PL 159 Idun). The field is being developed with an FPSO vessel and five subsea installations. Oil will be exported by offshore loading, and gas will be exported via the Åsgard export system. Production is expected to start in August 2011, and the total development cost is estimated by the operator BP to be NOK 36.4 billion.

Tyrihans, in which we hold an interest of 58.8%, is located in the Norwegian Sea and consists of two hydrocarbon accumulations: Tyrihans South (an oilfield with associated gas) and Tyrihans North (a gas field with a thin oil zone). The fields will be developed with subsea wells drilled and completed from five subsea templates, four dedicated production/gas injection and one for injection of raw sea water. The well stream will be transported in one pipeline to the Kristin platform for processing. Gas injection for reservoir pressure support is provided from Åsgard B through a gas injection pipeline to Tyrihans. Both the production pipeline between Tyrihans and Kristin and the gas injection pipeline between Åsgard B and Tyrihans, as well as the subsea well templates, were installed in 2007. Production is scheduled to start in mid-2009. The total development costs are estimated to be NOK 14.9 billion.

The **Vega/Vega Sør** project comprises the development of three separate gas-condensate accumulations: Vega Nord and Vega Sentral in PL248 and Vega Sør in PL090C. Our ownership interests in the licences are 60% and 45%, respectively. The fields are located in the North Sea. Three four-slot templates will be installed, and production will be transported to the Gjøa installation in a common pipeline. The total investments for the project are estimated to be NOK 7.9 billion. Production is scheduled to start in late 2010.

The **Yttergryta** subsea gas and condensate field development, with an investment value of approximately NOK 1.4 billion, is an excellent example of a relatively small but significant project in our portfolio, since it was developed so quickly. The discovery was made in the summer of 2007 and the PDO was submitted in January 2008. Production drilling commenced in September 2008 and the wellstream will be tied back to Åsgard B platform via Midgard flow line for processing and further export. We hold a 45.75% interest in the project. Production started in January 2009.

The table below shows some key figures for our major development projects.

Project	StatoilHydro's share	StatoilHydros investment [1]	Production start	Plateau production StatoilHydro's share [4]	Lifetime in years
Alve	85.000%	2.3	2009	21,000	12
Gjøa	20.000%	6.2	2010	19,000	15
Morvin	64.000%	5.8	2010	21,000	14
Skarv [2]	36.165%	13.2	2011	53,000	12
Statfjord Late Life	44.340%	8.7	2007	43,000 [3]	12
Tyrihans	58.840%	8.8	2009	56,000	17
Vega/Vega Sør	60%/45%	4.3	2010	30,000	13
Yttergryta	45.750%	0.6	2009	10,000	5

1) Estimated in NOK billion

2) Partner operated project

3) New additional production

4) Boe/day

3.1.6.2 Redevelopments

The following projects are being developed on the NCS to give existing installations a new lease of life or exploit new opportunities.

Oseberg Low Pressure involves the installation of two new production manifolds for low-pressure wells with tie-in to second stage separators. Production is planned to start in late 2009.

The **Snorre Redevelopment** project is defined as an IOR project and will contribute to achieve the Snorre Unit and Vigdis overall oil recovery ambition. The project includes a water injection pipeline from Statfjord C to the Vigdis field.

The **Statfjord Late Life** project will convert Statfjord into a mainly gas-producing field by changing the drainage strategy. Export of gas to the UK through a new pipeline connected to the existing pipelines to Flags and St. Fergus commenced in late 2007. The total investments in the project are estimated to be NOK 19.6 billion.

Troll Field projects includes the Troll B Gas Injection project and the Troll A P12 Pipeline Project. The main goal for these projects is IOR from Troll B and enabling the Troll field to maintain an average gas export capacity of 120 million standard cubic metres per day and a long term gas export capacity of 30 giga standard cubic metres per year.

The Troll B Gas Injection project includes two gas injectors in the Troll West Gas Province south. Start up is planned in 2011.

The Troll A P12 project includes a new 62.5 kilometres 36 inch pipeline between Troll A and Kollsnes, modifications on Troll A and interface with Kollsnes plant. Pipeline is planned to start in late 2011.

The Troll C - O2 Template, which will be located north west of the Troll C platform, is defined as an IOR project. The O2 Template will be tied back to the existing O1 Template, which is tied back to Troll C. Drilling is expected to start in late 2009 and production is planned to start in 2010.

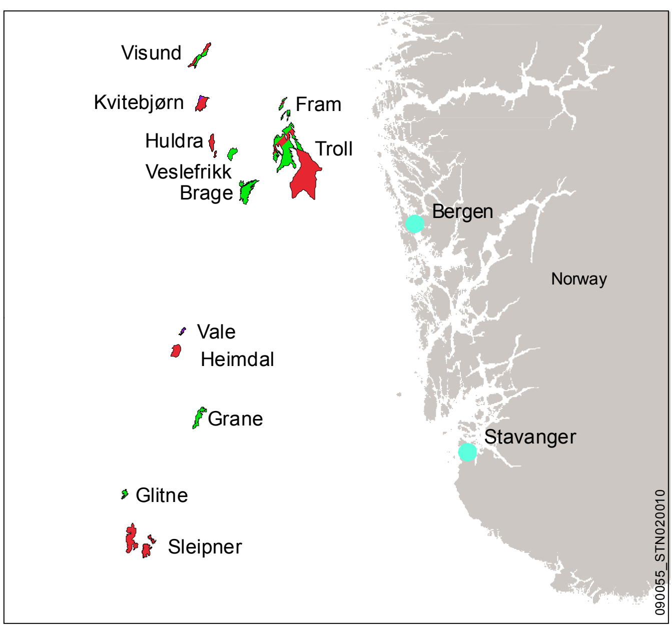
A new **low-pressure compressor module on Troll C** will be installed to increase capacity, and thereby production and recovery from Troll Vest. Production is planned to start in 2010.

Tune Sør is a single satellite well tied back via the Tune Main template to the Oseberg Field Centre. Tie-in and production start up are planned for mid-2009.

3.1.7 Fields in production

3.1.7.1 Operations North Sea

Operations North Sea covers a major part of StatoilHydro's production activity on the NCS, and there is focus on increasing and prolonging production in the area with priority on Improved Oil Recovery and the exploration and development of new fields.



Our producing fields in Operations North Sea are Troll, Fram, Sleipner, Kvitebjørn, Visund, Grane, Brage, Veslefrikk, Huldra, Glitne, Volve, Heimdal, Vilje and Vale. The area is dominated by the production of natural gas, as 59% of the equity production in 2008 was gas. The petroleum reserves are located under water depths of between 80 and 330 metres.

In 2008, StatoilHydro's share of the area's production was 250 mbbl of oil, condensate and NGL per day and 49 mmcm (1,732 mmcf) of gas per day, or 558 mboe in total per day.

Brage is an oilfield east of Oseberg in the northern part of the North Sea. The oil is sent piped to Oseberg and on through the pipeline in the Oseberg Transport System to the Sture terminal. A gas pipeline is tied back to Statpipe. A new discovery in the Knockando area in the early autumn proved very successfully and came on production in October this year.

Fram is connected to the Troll C platform for processing. Oil production started in 2003, and gas exports started in October 2007.

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

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

Heimdal is a gas field located in the northern part of the North Sea. Heimdal mainly operates as a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal, and gas from Oseberg is also transported via Heimdal. Heimdal had reduced regularity in 2007, which contributed to reduced production on Heimdal Vale and Huldra.

Sleipner consists of the Sleipner East, Gungne and Sleipner West gas and condensate fields. Condensate from the Sleipner field is transported to the gas processing plant at Kårstø. The gas from Sleipner has a high level of carbon dioxide, which is extracted on the field and re-injected into a sand layer beneath the seabed to reduce the carbon dioxide emissions to the air. We are currently exploring several prospects and discoveries in the Sleipner area that can potentially be tied in to Sleipner.

The **Troll** Area comprises Troll and Fram and the Vega and Gjøa development projects. Troll is the largest gas field on the NCS and a major oilfield. The Troll Field Project submitted a new Plan for development, operation and installation in June 2008 for IOR in the area.

In November we started test production for oil in the thin oil layers in the gas province of Troll East.

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

The first oil flowed from the **Vilje** field to the Alvheim floating production, storage and offloading vessel (FPSO) on 1 August 2008. The Vilje field is located in the northern part of the North Sea, north of the Heimdal field. Vilje is the first StatoilHydro-operated field on the Norwegian continental shelf tied in to an installation that is run by another operator.

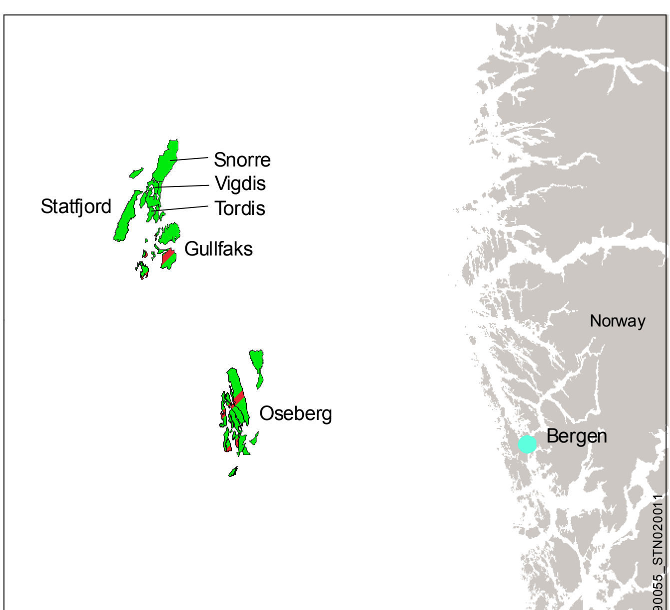
The **Visund** oilfield is located to the east of the Snorre field in the northern part of the North Sea. The field contains oil and gas in several tilted fault blocks with separate pressure and liquid systems. The oil is piped to Gullfaks A for storage and export. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes.

Volve is an oilfield located in the southern part of the North Sea approximately 8 kilometres north of Sleipner East. The development is based on production from the Mærsk Inspirer jack-up rig, with *Navion Saga* used as a storage ship to hold crude oil before export. Gas is piped to the Sleipner A platform for final processing and export. Volve started producing in February 2008.

The **Kvitebjørn** field resumed production on 27 January 2009 after being shut down since August 2008 due to a gas leak created by damage caused to the Kvitebjørn gas pipeline. The damage, which was caused by a ship's anchor, was discovered during an inspection, and production was shut down. Production resumed in January 2008 after surveys showed that the pipeline could be temporarily used for export. Repair work was scheduled for summer 2008, but during preparatory work for the repair, critical equipment underwent extensive functional testing and parts of the equipment failed. Consequently, the repair was postponed until 2009. While making a routine inspection on the pipeline after the planned maintenance stop in August 2008, we discovered a gas leak from the pipeline and production was immediately stopped.
Gas exports from Visund, which also uses the pipeline, were also affected by the pipeline damage.

3.1.7.2 Operations West

The Operations West area contains light oil petroleum resources in a compact geographic area in which StatoilHydro is the sole operator. The main producing fields in the Operations West area are Statfjord, Gullfaks, Snorre, Oseberg, Tordis and Vigdis.



Our share of the area's production in 2008 was 355 mbbl per day of oil, condensate and NGL, and 19 mmcm per day (682 mmcf per day) of gas, or 477 mboe per day in total. Operations West is the leading oil producing area on the NCS and, even after 20 years of production, we believe there are still substantial opportunities for increased value creation.

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

In 2008, Operation West performed five turnarounds within the scheduled time frame and without severe HSE incidents.

The **Gimle** field is a Gullfaks satellite field and is operated as a separate Unit. Permanent production started in May 2006, converting the Gimle exploration well drilled from the Gullfaks C platform into a production well. By the end of 2008, Gimle consisted of two producers and one injector, all drilled as long-reach wells from the Gullfaks C platform.

Due to high depletion of the reservoir, production from Gullfaks South, Statfjord reservoir was temporarily shut down in October 2008. The production will be started up again when a new water injection well has been drilled.

Gullfaks has been developed with three large concrete production platforms. Oil is loaded directly into custom-built shuttle tankers on the field. Associated gas is piped to the Kårstø gas processing plant and then on to continental Europe. Four satellite fields, Gullfaks South, Rimfaks, Gullveig and Skinfaks, have been developed with subsea wells remotely controlled from the Gullfaks A and C platforms.

Gulltopp. A long-reach well has been drilled from the Gullfaks A-platform to develop the Gulltopp field. Gulltopp, which was discovered in 2002, is a small oilfield. Due to several operational problems, the well was temporarily plugged in the third quarter of 2006. Drilling resumed in October 2007, and the well was started up in 2008 producing considerably more than initially estimated.

The **Oseberg** area includes the main Oseberg field developed with Field Centre installations and the Oseberg C production platform, and two satellite fields, Oseberg East and Oseberg South, developed with production platforms. In addition, the Tune field and Oseberg West Flank have been developed with subsea installations and tied back to the Oseberg Field Centre. Oil and gas from the satellites is piped to the Oseberg Field Centre for processing and transportation. Oil is exported to shore through the Oseberg transportation system, and gas is exported through the Oseberg gas transportation system to Heimdal and on to market.

Oseberg Delta is a subsea gas and oil development of the resources in the Delta structure in block 30/9 that makes use of Oseberg Field Centre facilities for processing and export. Production started June 2008.

Oseberg Gamma Statfjord is developed with two wells from Oseberg B. Oil production started in April, and water injection commenced in August 2008.

Theta Cook was drilled as an exploration well from Oseberg C, converted directly to an oil producer and started in June 2008.

Oseberg Field Centre celebrated 20 years of production in December 2008.

The **PL 089** asset includes the Vigdis, Borg and the Tordis fields. The Tordis field and the southern part of the Borg field have been developed with seven subsea satellites and two templates tied back to Gullfaks C, where the oil and gas is processed and stored for offshore loading and export. A subsea separator, boosting and injection unit was installed on Tordis in 2007 (Tordis SSBI), and most of the water from Tordis was injected through a dedicated water injection well into the Utsira formation.

A leakage of produced water through the seabed was observed in May 2008, and the water injector was shut down resulting in reduced production from Tordis. The Tordis SSBI is planned to be started up in late 2009 or early 2010 with an alternative solution for the produced water disposal.

The Vigdis field was developed in 1997 with three subsea templates with a well stream through pipelines connected to Snorre A, where the oil is stabilised and exported to Gullfaks for storage and loading. The northern part of Borg is also produced via the Vigdis templates. The Vigdis Extension Phase 2 project was completed early in 2008.

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

By July 2008 the Snorre field had produced 1000 mmboe of oil since field start-up.

Inspection revealed internal damage to three risers on Snorre B in the autumn of 2008, resulting in shut-down of risers and reduced production. The risers are expected to be replaced in late 2009 or early 2010.

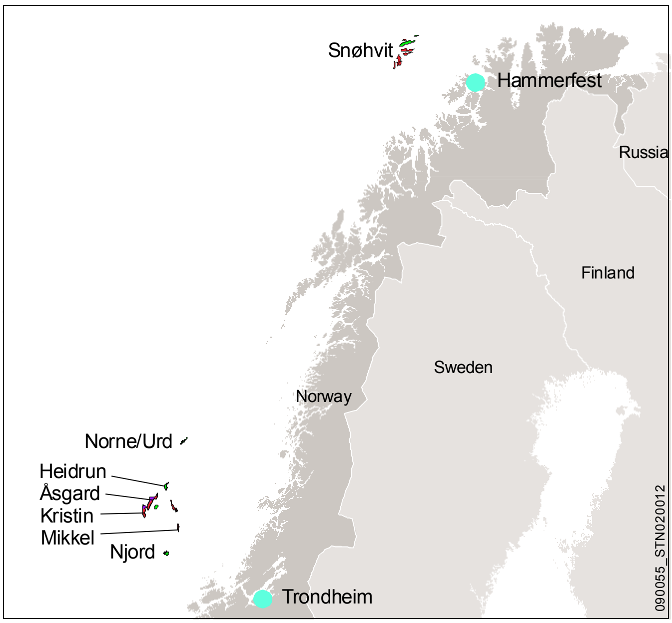
Statfjord has been developed with three fully-integrated platforms supported by gravity base structures featuring concrete storage cells. Each platform is tied to offshore loading systems for loading oil into tankers. Associated gas is piped through the Tampen link to the UK or, alternatively, to the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

During modification work in the equipment shaft on 24 May 2008 an oil leakage from hot-tap equipment occurred. This resulted in an explosive atmosphere in parts of the shaft, and 50-70 cubic metres oil was pumped to sea to avoid escalation. Most of the personnel on board were evacuated, and no personal injury occurred.

Due to integrity problems, the Statfjord Nord Satellite injection facility was shut down in November 2008. The field's production is currently reduced and is expected to be shut in early 2009. Equipment will be replaced during 2009.

3.1.7.3 Operations North

Our producing fields in the Operations North area are Åsgard, Mikkel, Heidrun, Kristin, Norne, Urd, Njord and Snøhvit. The Yttergryta field started production in January 2009 and the Alve field started production in March 2009.



Our share of the area's production in 2008 was 250 mbbl per day of oil, condensate and NGL, and 46 mmcm per day (777 mmcf per day) of gas, or 314 mboe in total per day.

This region is characterised by petroleum reserves located at water depths between 250 and 500 metres. The reserves are partly under high pressure and at high temperatures. These conditions have made development and production more difficult and have challenged the participants to develop new types of platforms and new technology, such as floating processing systems with subsea production templates. We plan to increase efficiency by further coordinating our operations in the area and by stemming the decline in production from the mature fields through increased seismic activity and well maintenance. In addition, we intend to expand our activities by utilising our installed production and transportation capacity before building new infrastructure.

The **Heidrun** platform is the largest concrete tension leg platform ever built. Most of the oil from Heidrun is shipped by shuttle tankers to our Mongstad crude oil terminal for onward transportation to customers. Gas from Heidrun provides the feedstock for the methanol plant at Tjeldbergodden in Norway. Additional gas volumes are exported through the Åsgard Transport System (ÅTS) to gas markets in continental Europe.

Kristin is a gas condensate field in the south-western section of the Operations North area. The Kristin development is the first high-temperature/high-pressure (HTHP) field developed with subsea installations. The pressure and temperature in the reservoir - 900 bar and 170 degrees Celsius, respectively - are higher than any other developed field on the NCS. The stabilised condensate is exported to a joint Åsgard and Kristin storage vessel, and the rich gas is transported to shore via the ÅTS to the gas processing facility at Kårstø. In 2008, the last of twelve wells was completed and entered into production.

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

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

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

Snøhvit is the first developed gas field in the Barents Sea. Twenty wells will produce natural gas from three gas reservoirs: Snøhvit, Askeladd and Albatross. All the offshore installations are subsea, which makes Snøhvit one of the first major developments without production facilities offshore.

The natural gas is transported to shore through a 143-kilometre long pipeline and it is landed at Melkøya, where it is processed at our LNG plant. This plant is Europe's largest export factory for LNG. LNG is shipped to customers in Europe and the USA in tankers. The first shipment took place in late 2007.

The LNG plant has suffered from operational challenges and there are still some uncertainties related to the timing of regular and stable operations. Performance and regularity has been significantly improved through 2008. One major maintenance stop in 2009 is planned to achieve further increases in capacity and regularity.

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

The **Åsgard** field contains three fields: Smørbukk, Smørbukk South and Midgard. The field was developed with the *Åsgard A* production ship for oil, the Åsgard B semi-submersible floating production platform for gas and the *Åsgard C* storage vessel. The subsea production installations are the most extensive in the world, with a total of 53 wells grouped in 18 seabed templates. Furthermore, the Åsgard B platform is the largest floating gas processing centre in the world and *Åsgard A* is one of the largest floating production ships ever built.

The Åsgard development links the Haltenbanken area to Norway's gas transport system in the North Sea. Gas from the field is piped through the Åsgard Transport System (ÅTS) to the processing plant at Kårstø and on to receiving terminals in Emden and Dornum in Germany. Oil produced at the *Åsgard A* vessel and condensate from the *Åsgard C* storage vessel are shipped from the field in shuttle tankers.

3.1.7.4 Partner operated fields

Partner-operated fields represent a significant proportion of StatoilHydro's oil and gas portfolio. The portfolio ranges from development projects to mature fields, and the complexity of these requires detailed knowledge of the areas involved.

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

Ekofisk is the oldest field complex in operation on the Norwegian Continental Shelf. The operator is ConocoPhillips. It consists of the fields Ekofisk, Eldfisk and Embla (StatoilHydro's interest 7.604%) plus Tor (StatoilHydro's interest 6.639%). Ekofisk has been upgraded with several new platforms over the years, the latest was 2/4-M installed in 2005. Several new projects are being studied; a new Ekofisk Hotel and fields centre, a new Ekofisk South drilling platform and redevelopment of Eldfisk. Final decisions are expected to be taken during the next few years. These new platforms are expected to extend the field life beyond the current licence period which ends in 2028.

Ormen Lange, a deepwater gas field in the Norwegian Sea, is the second largest gas field on the NCS. StatoilHydro has an interest of 28.92%. StatoilHydro was the operator for the development phase and Norske Shell became the operator for the production phase that began at the end of 2007. StatoilHydro continues to execute approved, but not yet completed, parts of the subsea development. Ormen Lange extends across three production licences. The selected development is an extensive seabed development at depths ranging from 850 to 1,100 metres. The well stream is transported to an onshore processing and export plant at Nyhamna. Sales gas is transported through a dry gas pipeline, Langeled, via Sleipner to Easington in the UK.

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

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

StatoilHydro has a 10% interest in the **Skirne** gas and condensate field, which is operated by Total. The field has two subsea templates. The well stream is transported to Heimdal for processing. From there gas is transported in Vesterled or Statpipe. The condensate is transported to Brae/Forties in the UK sector.

3.1.8 Decommissioning

There has been no decommissioning of StatoilHydro-operated fields during the last three years.

The Norwegian government has laid down strict procedures for the removal and disposal of offshore oil and gas installations under the Convention for the Protection of the Marine Environment of the Northeast Atlantic, known as the OSPAR Convention. However, there has been no decommissioning of StatoilHydro-operated fields during the last three years. On partner-operated fields there has been removal activity at Frigg and Ekofisk.

3.2 International E&P

3.2.1 Industry overview

The global financial crisis and the subsequent recession which the global economy entered in the second half of 2008 has inevitably also had an impact on the global upstream oil and gas industry.

We have witnessed high volatility in oil and gas prices with concerns about availability dominating the first half of 2008. As the reality of the current global situation became more evident in the second half of the year, prices were subsequently impacted by downward adjustments to energy demand forecasts. This combined with a heightened risk aversion in speculative capital led to oil (Brent dated) being traded around USD 100 lower in December 2008 than at July 2008's all time high of USD 144 per bbl.

The industry has experienced a rapid increase in costs and capital expenditures over the past three to four years. This has been both as a result of limited competition and capacity in the service industry together with increased complexity of new projects. Although it could be expected that lower oil and gas prices and a lower volume of overall industry activity would contribute to a downward pressure on costs in the services and manufacturing industry, the technical challenges from increasing project complexity are unlikely to relent and will maintain an upward structural pressure on costs. In this environment, the industry is expected to increase its focus on cost control and capital deployment efficiency through tightening prioritisation among existing opportunities.

International politics and adjustments to energy policies have also continued to influence the business environment in resource-rich countries across the world. In the short to medium term, there could be a potential for improved access and fiscal terms in some regions as a result of the global turmoil. However, it will not reduce the need for a continuous focus on building and leveraging technical and commercial capabilities in order to turn oil and gas resources into productive capacity.

In recent years the industry has been characterised by a much higher level of competition, both in terms of the number and type of participants. This is unlikely to change. However, the sharp fall in share prices generally combined with the degree to which companies have access to capital to fund their future developments could act as catalysts to create change in the competitive landscape.

The long-term challenge of providing the world with secure, affordable and environmentally acceptable energy remains as challenging a reality as ever. In combination, the above developments within the industry are likely to result in a continued highly competitive environment for scarce international upstream opportunities.

3.2.2 Portfolio management

Our strategy is to develop key positions in four focus areas: deep water, heavy oil, gas value chains and harsh environments. It is also the framework for new growth and portfolio optimisation.

In November 2008, StatoilHydro formed a strategic alliance with **Chesapeake Energy Corporation**, USA. The deal was completed in December 2008, with the purchase of a 32.5% interest in **Chesapeake's Marcellus shale gas** acreage in the Appalachia region of the northeastern USA. We paid USD 1.3 billion in cash and will pay a further USD 2.1 billion in the form of a 75% carry on drilling and completion of wells during the period 2009 to 2012. We have the right to a 32.5% participation in additional Chesapeake leases in the Marcellus shale play. In addition, the strategic alliance includes jointly exploring unconventional gas opportunities worldwide. The Chesapeake deal is another step in developing our gas value chain business expertise outside of Europe.

In March 2008, we signed an agreement with Anadarko to acquire its remaining 50% interest of the **Peregrino** heavy oil field in Brazil. The transaction was formally closed on 11 December 2008, making StatoilHydro 100% owner and operator of the field. The sale was effective 1 January 2008. The oil production is expected to start in 2011 and StatoilHydro will subsequently become one of the largest foreign oil producers in Brazil.

In 2008 we closed the sale of all our shallow water assets on the Shelf in the **Gulf of Mexico (GoM)** to Mariner Energy, Inc. for a cash consideration of USD 0.2 billion. The transaction was accomplished through the sale of our wholly owned subsidiary Hydro Gulf of Mexico, LLC. The sale was effective 1 January 2008. StatoilHydro remains one of the largest acreage holders in GoM deepwater with a strategic focus on high prospectivity deepwater areas. See note 3 business combinations for more information.

On 9 February 2008, Sincor in Venezuela was transformed into an incorporated joint venture known as **Petrocedeño, S.A.** and partially nationalized. Our share was reduced from 15% in Sincor to 9.677% in Petrocedeño. The agreed compensation has been received in full from the Venezuelan government.

Renegotiations of PSAs by the NOC in Libya have resulted in a reduced equity share. Our equity share of production in **Murzuq** was reduced from 8.0% to 2.4% effective as of 1 January 2008. Renegotiations are ongoing for **Mabruk**.

In April 2008 we completed the divestment of our interest in the **UK fields Dunlin** (28.76%) and **Merlin** (2.35%), the Brent Pipeline system and the Sullom Voe Terminal located on the Shetland Islands to Fairfield and Mitsubishi. Effective date of sale was 1 January 2008.

3.2.3 Exploration activity

Over the last years we have been continuously accessing new exploration licences with high resource potential and moderate risk at the drilling stage to maximise the number of impact wells.

We have exploration licences in North America (Canada and the USA), Latin America (Brazil, Cuba and Venezuela), Africa (Algeria, Angola, Egypt, Libya, Morocco, Mozambique, Nigeria and Tanzania), the European, Caspian and Russian area (Denmark, the Faroes, Ireland, the UK and Azerbaijan), and the Middle East and Asia (Iran, India and Indonesia).

Since 2002 we have carried out a major global screening of oil and gas basins to rebuild our exploration portfolio and we have added significant resources and targeted new high-potential basins globally. In 2008 we have been high-grading the portfolio to better utilize the overall competence pool of StatoilHydro internationally.

In 2008 we have also been further high-grading prospects for our short-term drilling programme. This entails prioritising and sequencing the most prospective drilling targets, optimising allocation of the rig fleet and providing a dedicated exploration organisation. We will continue to high-grade the portfolio in 2009 and the years to come. We plan to drill approximately 35 wells in 2009.

We completed 40 wells in 2008 and nine were ongoing at 31 December 2008. Of 40 wells, eight were announced as discoveries at year end, one was annouced in first quarter 2009 and 18 are currently under evaluation. Five of the nine ongoing wells were completed in the first quarter 2009, and one of them have been announced as a discovery.

The areas where we entered or had significant activity in 2008 are presented below.

3.2.3.1 North America

3.2.3.1.1 Canada

StatoilHydro is operator and partner in prospects off the coast of Newfoundland and we have acquired 1100 square kilometres of oil sand deposits in Alberta.

Offshore
In November 2008 the Newfoundland and Labrador authorities announced that we were awarded two licences, one as operator with 65% interest in the Flemish Pass Basin with Husky as partner, the other with 50% interest in the Jeanne d'Arc Basin with Petro-Canada as the operator.

The licenses were awarded based on a work expenditure bid with no legal obligation to perform the work program. If no work program is committed during the five first years, 25% of the bid has to be paid. The licenses were formally awarded in January 2009.

In 2008 a 3D seismic survey was acquired and processed on the two operated licenses in the southern part of the Jeanne d'Arc Basin near the Terra Nova Field. StatoilHydro holds a 50% interest in both licenses.

Drilling operations at the Mizzen exploration well in license EL 1049 in the frontier Flemish Pass basin started at the end of the year with StatoilHydro as the operator with a 65% interest. The well is expected to be completed in 2009.

In 2009 activities will also include the planned drilling of an exploration well on EL 1092 operated by Petro-Canada. We have a 50% interest in this license. Evaluation of the existing licenses will aim to identify new drillable prospects.

Oil Sands

We have an interest in 1114 square kilometres (275,213 net acres) of oil sands leases located in the Athabasca region of Alberta. In order to determine the extent of the exploitable oil sands deposits in Alberta, a total of more than four hundred wells were drilled in the region from 2003 to 2008. In addition, 2076 square kilometres of 2D seismic and 210 square kilometres of 3D seismic have been acquired. The oil sands exploration program has been reduced, and only wells required for delineation, observation and water source or disposal for Corner and Leismer Expansion remain in the 2009 winter drilling programme.

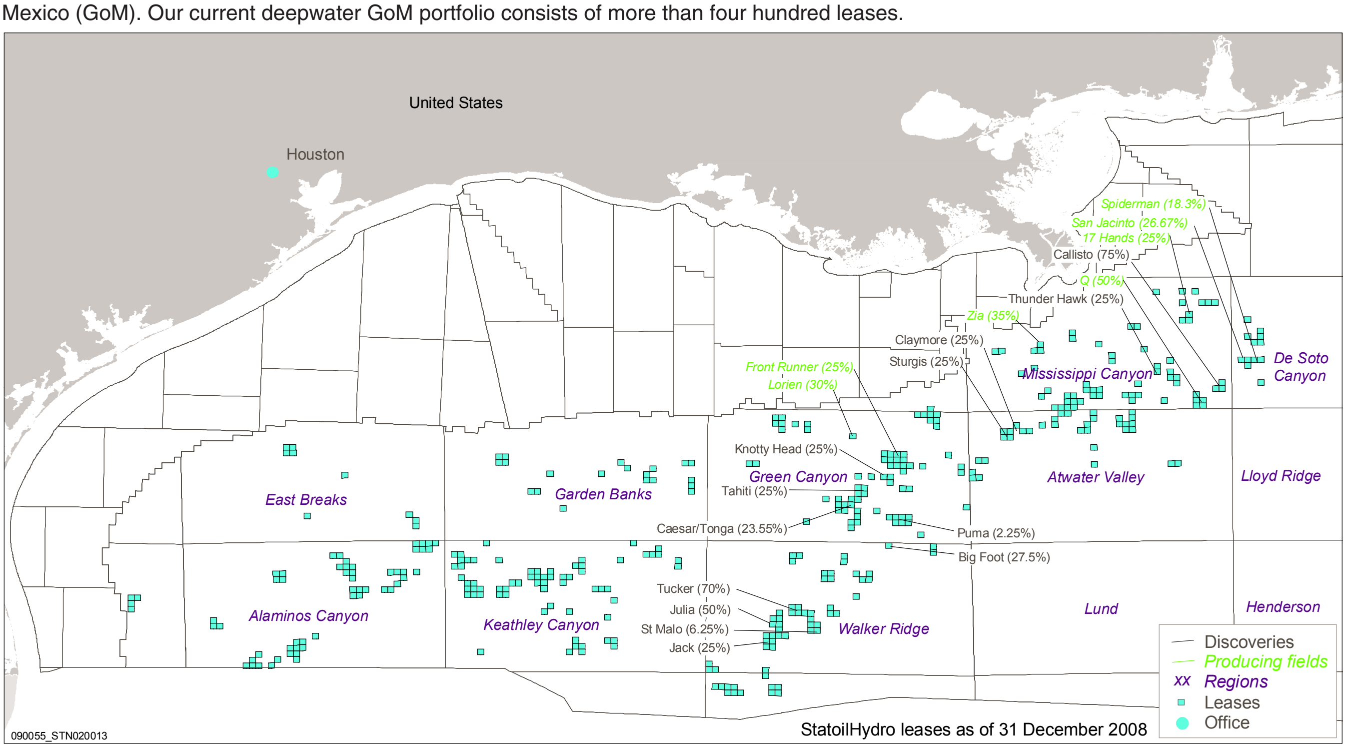
Our oil sand activities are described in more details in section 3.2.6.1.1 Operational review-International E&P-Fields in development and production-North America-Canada.

3.2.3.1.2 The USA

StatoilHydro has significant activities in the USA, with more than 400 leases in our Gulf of Mexico portfolio, and several wells to be drilled in coming years. We were also awarded 16 leases in Alaska in 2008.

US Gulf of Mexico

Since 2003, we have established a significant deepwater portfolio and we are one of the largest deepwater acreage holders in the Gulf of Mexico (GoM). Our current deepwater GoM portfolio consists of more than four hundred leases.



During 2008 we completed nine exploration wells and appraisal wells. Appraisal well Big Foot 3, sidetrack number two, has confirmed the same pay intervals of the previously announced discovery and sidetrack well. Three additional wells were ongoing at year end. Two of them have been completed in first quarter with one announced discovery.

We were awarded 21 deepwater blocks in the Central Lease Sale 205 in the first quarter of 2008. We participated in the Central Lease Sale 206 and Western Lease Sale 207 held in 2008. Following the sales we were awarded 16 leases from Central Lease Sale 206 and five leases from Western Lease Sale 207 . We participated in the Central Lease Sale 208 in March 2009.There are no work commitments associated with Gulf of Mexico leases.

In 2008 we have signed an agreement with the Colombian oil company Ecopetrol America inc. under which the two companies will form a Joint Exploration Team for the Gulf of Mexico and drill three or more wells in the coming years. Ecopetrol will farm in with interests of 20 to 30% in the wells covered by the agreement.

We have contracted two newly built rigs, Maersk Developer (joint contract with Woodside) and Discoverer Americas, which are expected to arrive in the Gulf of Mexico during 2009. These rig slots will be used to drill exploration and appraisal wells on our operated exploration acreage. In addition we expect to participate as a partner in a number of exploration and appraisal wells.

Alaska

In 2008 we were awarded 16 leases in Chukchi Sea Lease Sale 193 in Alaska. Fourteen of these were joint bids with ENI Petroleum. We are the operator of all leases. The Chukchi Sea is located offshore Alaska northwest of Prudhoe Bay, in water depths less than 100 metres. The area is considered a frontier area with no production or infrastructure as of today. There are no work commitments associated with Alaska leases.

3.2.3.2 Latin America

3.2.3.2.1 Brazil

We have interests in eight exploration licences in four different basins in offshore waters in Brazil. We are the operator of four of the licences.

We have one commitment well in BM-CAL-10, one in BM-CAL-7, two commitment wells in BM-C-33 and one commitment well in licence BM-C-47 from the 9th Bid Round, awarded in March 2008.

A 30% interest in blocks S-M-1105 and 1109 and the operatorship and a 40% interest in block S-M-1233 in the 8th Bid Round are still pending award by the government.

One exploration well spudded in 2008 in block BM-J-3 was completed in 2009. Petrobras is operator, and our share is 40%.

3.2.3.3 Africa

3.2.3.3.1 Algeria

We are the operator and have 75% interest in the exploration phase for the Hassi Mouina block. This block extends over 23,000 square kilometres and is situated in the western/central part of the Sahara in an under-explored area.

Hassi Moina exploration.

Three discoveries were announced in 2008. In 2008 we were granted an additional two year exploration period which expires in March 2010. The extension included a 30% relinquishment of the licence area.

All commitments in the licence are fulfilled. In 2009 two additional appraisal wells will be completed. In addition to this a 3D campaign will be carried out across the discovery regions of the block.

During 2008 an internal team has worked on maturing the technical solutions for a possible commercial development of the Hassi Mouina discoveries.

3.2.3.3.2 Libya

StatoilHydro operates three exploration licences in Libya totalling over 23,000 square kilometres.

Exploration drilling in licence 171- Kufra.

Area 94 covers an area of 9,849 square kilometres on the south-eastern Cyrenaica Platform with a commitment of one exploration well and 2D seismic. The commitment well was spudded in 2009. We have a 100% interest in this area.

Area 146 covers an area of 2,492 square kilometres in the Murzuk basin with a work commitment of 2D seismic and two exploration wells. We have a 100% interest in this area.

Area 171 covers an area of 11,305 square kilometres in the Kufra basin with a work commitment of two exploration wells and 2D seismic. The first commitment well was drilled in 4Q 2008. We have a 50% interest in this area.

In addition, we have a 20% exploration interest in **Area 186,** operated by Repsol. Nine wells were drilled during 2008.

3.2.3.3.3 Egypt

We are operator with an 80% interest in two offshore exploration licences located in the Mediterranean, west of the Nile Delta in water depths ranging from sea level to 3000 metres. Production sharing agreements for both blocks were signed in July 2007.

El Dabaa Offshore (Block 9) covers an area of 8368 square kilometres. We are committed to drilling one exploration well and conducting 2D and 3D seismic surveys over a four-year period. We have acquired and are evaluating the seismic surveys. Drilling is planned to commence in 2010.

Ras El Hekma Offshore (Block 10) The block covers an area of 9802 square kilometres. The related work commitment includes 2D and 3D seismic surveys over a four-year period. 2D seismic acquisition and processing is complete. 3D seismic has been acquired and processing is scheduled for completion in 2009.

3.2.3.3.4 Angola

StatoilHydro holds interests in blocks 4/05, 15, 15/06, 17, 31 and 34 in Angola. Twelve wells were completed in 2008, with four announced as discoveries.

Block 4/05 in which we have a 20% interest is operated by Sonangol. The licence was given a two year extension with a well commitment. One exploration well was drilled in 2008.

Block 15 exploration licence with ExxonMobil as operator has expired. Areas with proven oil have been converted to Development Area (DA) and Provisional Development Areas (PDA). A total of 36 exploration and appraisal wells have been drilled on the original Block 15 and offspring DA's and PDA's. In 2008 two appraisal wells were drilled. We have a 13.33% interest in this block.

Block 15/06 in which we have a 5% interest is operated by Eni. The work commitment for Block 15/06 is extensive, covering 3D seismic surveys and the drilling of eight wells, to be carried out during the first five years of the exploration phase. The 3D commitment was fulfilled and two of the eight exploration wells were drilled in 2008, both announced as discoveries.

Block 17 in which we have a 23.33% interest is operated by Total. To date, a total of 32 exploration and appraisal wells have been drilled and all exploration commitments have been met. In 2008 two exploration wells were drilled.

Block 31 in which we have 13.33% interest is operated by BP. In 2008, five exploration wells were completed with two announced discoveries and to date a total of 26 exploration wells have been drilled in the block. The licence was given a two year extension with a commitment of four wells. The exploration period ends in 2010.

Block 34 in which we have a 50% interest is operated by the Angolan national oil company Sonangol P&P, and we are the technical assistant to the operator. In 2005, Sonangol P&P signed an agreement with the concessionaire to enter into the second exploration phase for Block 34 with a one well commitment. The licence was given a three year extension with no additional well commitment. The period expires in 2011.

3.2.3.3.5 Nigeria

StatoilHydro is operator for two deepwater exploration licences, OML 128 and OML 129. In addition, we have shares in two exploration licences, OPL 315 operated by Petrobras and OPL 242 operated by Ocean Energy (Devon).

OML 128. We have a 53.85% interest in OML 128. The Agbami field straddles OML 127 and OML 128. [OML 128] came on stream in July 2008. The remaining prospectivity in the licence will be re-assessed in 2009, based on information from the Bilah and NnwaDoro evaluations.

OML 129. We have a 53.85% interest in OML 129. There are two discoveries in the block, Bilah and Nnwa. Only one well has been drilled in the **Bilah** condensate discovery.

The **Nnwa** discovery extends into the Shell-operated Block OML 135 (known as the Doro structure). The joint StatoilHydro and Shell subsurface project which was started in 2007 was completed mid-2008 and the results have been presented to the Nigerian Authorities.

OPL 315. We have 45% interest in block OPL315. The licence is committed to carry out a work programme by February 2011 consisting of one well and a seismic survey.

OPL 242. We have a 15% interest in OPL 242. All exploration obligations have been fulfilled and we are in the process of relinquishing the licence.

We had interests in OPL 324 and OPL 256 but these blocks were relinquished in 2008.

3.2.3.3.6 Tanzania

StatoilHydro is operator with a 100% interest in Block 2. The total area of Block 2 is 11,099 square kilometres and it lies in water depths of between 400 and 3000 metres. This is a frontier area, as no wells have been drilled this far from the coast.

The exploration period started in 2007 and is divided into three stages:

- The first exploration period of four years with a 2D seismic commitment
- The first extension period of four years with a one well drilling commitment
- The second extension period of three years with a one well drilling commitment

A 6200-kilometre 2D seismic survey was acquired during the first quarter of 2008. Final processed data was delivered in January 2009. According to the latest estimates the earliest time for first drilling will be in 2011.

3.2.3.4 Europe, the Caspian region and Russia

3.2.3.4.1 United Kingdom

Our Statoil UK subsidiary produces oil and gas and conducts exploration on the UK continental shelf, where we have interests in more than 100 North Sea and Atlantic margin blocks.

StatoilHydro is a 30% partner in a group of Chevron-operated exploration licences west of Shetland. In late 2008 drilling commenced on an exploration well on Rosebank / Lochnagar North.

In 2008 Hess drilled a discovery well on the Amos Prospect which is located four kilometres south of Schiehallion. StatoilHydro has a 17.65% interest in this discovery.

In 2008 a high resolution 3D seismic survey and a pilot ocean bottom cable seismic programme were acquired over the Mariner Field. Also in 2008, a well was drilled on Bressay and tested. In addition, in this heavy oil area, StatoilHydro completed a well on the Broch Prospect (9/11e-14).

The Mariner and Bressay heavy oil fields have been established as development projects but with further appraisal drilling ongoing. These fields are described in report section 3.2.6.4.1 *Operational review, International E&P-Fields in development and production-Europe*, Caspian region and Russia-United Kingdom.

3.2.3.4.2 Azerbaijan

We have a 25.5% interest in the Shah Deniz licence operated by BP. All exploration commitments have been fulfilled. There was a major gas-condensate discovery in 2007 confirming sufficient gas at Shah Deniz for a second stage development.

A further appraisal well (SDX-5) was spudded in the south-eastern part of the structure in 2008, and is expected to be completed in 2009.

We signed an exploration, development and production sharing agreement (PSA) in 1998, with BP as operator, covering the **Alov, Araz and Sharg** structures.

We have a 15% interest in this PSA, which is located roughly 150 kilometres south-east of the Azeri capital of Baku. The contract area covers about 1400 square kilometres and is located in water depths of 450 to 800 metres. The structures are located in the area of the Caspian Sea that is the subject of a dispute between Azerbaijan and Iran, and, since the contract was signed, Iran has claimed that parts of the area are in Iranian waters. Negotiations with SOCAR, the State Oil Company of Azerbaijan, have resulted in a freezing of the licence fee until the border issue is resolved.

3.2.3.4.3 The Faroes

StatoilHydro was awarded a 50% interest in one lease with operatorship in 2008. We are now the operator of five licenses in the Faroe Islands and partner in one in which Chevron is the operator.

3D seismic operations have been conducted in licence 009 and 011 during 2008.

3.2.3.5 Middle East and Asia

3.2.3.5.1 Indonesia

StatoilHydro has agreements which give us interests in the deepwater Kuma and Karama blocks off Indonesia, where the water depth ranges from 1000 to 2000 metres.

In 2008 we acquired 2297 square kilometres of 3D seismic data over the Karama PSC and have fulfilled our seismic work obligation. Within the Kuma PSC, 1044 square kilometres of 3D seismic data have been acquired. A contract for using the drillship Global Santa Fe Explorer was signed by a consortium of six oil companies including StatoilHydro in 2008. The contract is for two years with a one year extension option. The three commitment wells in the Karama PSC will be drilled in 2011, while the Kuma well is expected to be drilled in late 2010 or early 2011. Drilling preparations will be initiated for all operated and non-operated wells.

A two year extension of the Memorandum of Understanding (MOU) with Pertamina was signed in October 2008.

3.2.3.5.2 India

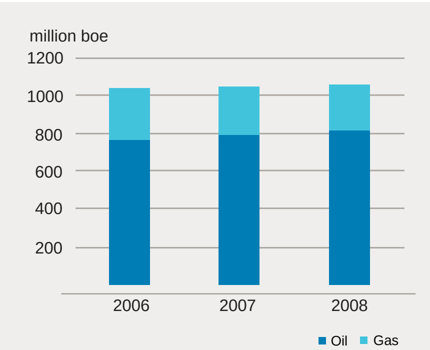
StatoilHydro has an agreement with the Indian state oil company Oil and Natural Gas Corporation (ONGC) that gives us access to exploration acreage off India, mostly in deep waters.

In July 2008 the Indian Government approved the assignment of a 10% participating interest in Block KG-DWN-98/2 to StatoilHydro in accordance with a previously signed farm-out agreement. Block 98/2 is located on the East coast of India in the Krishna Godavari Basin. ONGC is operator with a 65% interest. The block covers an area of 7295 square kilometres. Several discoveries have been made in the block, and both gas and oil have been encountered.

3.2.4 Oil and gas reserves

This section describes our international oil and gas reserves and explains changes that have had an effect on the reserves balance.

OIL AND GAS RESERVES



The proved reserves of the international business area increased by 2% in 2008, from 1039 mmboe to 1055 mmboe.

The increase in the proved reserves estimate in 2008 reflects the effect of lower oil prices on entitlement production for international projects with a Production Sharing Agreement or a Buy Back Agreement.

Several purchase and sale agreements and change of ownership were finalised in 2008 having effect on the international reserves balance:

- The purchase of Anadarko's 50% share in Peregrino was finalised late in 2008 and contributed positively to the international reserves balance.
- On 9 February 2008, Sincor in Venezuela was transformed into an incorporated joint venture known as Petrocedeño, S.A. and partially nationalised, resulting in a change of our share from 15% to 9.677% and a reduction of proved reserves.

- The sale of our Shelf portfolio in Gulf of Mexico was effective from 1 January 2008, resulting in reduction in proved reserves.

Acquisition of a share in the Marcellus shale gas play in the USA was completed December 2008, but no reserves are booked in 2008. With few wells in production, limiting the reserves that can be booked by the year end, StatoilHydro has not included the Marcellus shale in the 2008 proved reserves estimation.

North American Oil Sands Corporation was officially taken over by StatoilHydro in the middle of 2007, but the current maturity level and recovery techniques of the asset do not yet justify recognition of proved reserves.

The share of developed reserves at year-end is 536 mmboe, which is up 17.5% from 2007. Of the 2008 proved developed reserves, 406 mmboe are oil/NGL and 20.6 bcm (727 bcf) are natural gas. The increase in proved developed reserves is primary related to production start-up of developments in Angola and future development in fields in Azerbaijan and Libya.

The following table shows our total international proved reserves as of 31 December for each of the last three years. Further information on reserves can be found in note 34 - Supplementary oil and gas information - to our Consolidated Financial Statements.

Year		Oil/NGL mmbbls	Natural gas bcm	Natural gas bcf	Total mmboe
2008	Proved reserves end of year	**805**	**39.7**	**1,403**	**1,055**
	of which, proved developed reserves	**406**	**20.6**	**727**	**536**
2007	Proved reserves end of year	785	40.4	1,426	1,039
	of which, proved developed reserves	323	21.2	748	456
2006	Proved reserves end of year	756	44.3	1,567	1,032
	of which, proved developed reserves	334	8.0	283	385

3.2.5 Production

This section describes our production outside Norway.

StatoilHydro's petroleum production outside Norway amounted to an average of 290 mboe per day entitlement production and 465 mboe per day equity production in 2008. The total annual entitlement production in 2008 was approximately 106 mmboe compared with 112 mmboe in 2007.

	For the year ended 31 December								
	2008			2007			2006		
Production	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe
Total	**232**	**9**	**290**	252	9	307	194	6	234

The first table shows our average daily entitlement production of oil, including NGL and condensates, and natural gas for each of the years ending 31 December 2008, 2007 and 2006. New fields that came on stream in 2008 were Mondo and Saxi-Batuque in Angola, Deep Water Gunashli in Azerbaijan, Agbami in Nigeria and South Pars in Iran. In addition we purchased a 32.5% interest in the Marcellus shale gas acreage in the USA.

Field	StatoilHydro's equity interest	Operator	On stream	License expiry	Producing wells	Development wells
North America						
Canada: Hibernia	5.00%	HMDC	1997	2027	31	1
Canada: Terra Nova	15.00%	PetroCan	2002	2022	15	0
USA: Lorien	30.00%	Noble	2006	2012	2	0
USA: Front Runner	25.00%	Murphy Oil	2004	2010	6	0
USA: Spiderman Gas	18.33%	Anadarko	2007	2012	3	0
USA: Q Gas	50.00%	StatoilHydro	2007	2014	1	0
USA: San Jacinto Gas	26.67%	ENI	2007	2012	2	0
USA: Zia	35.00%	Devon	2003	2008 [1]	1	0
USA: Seventeen Hands	25.00%	Dominion	2006	2010	1	0
USA: Marcellus shale gas	32.50%	Chesapeake	2008	n/a	24	4
Latin America						
Venezuela: Sincor [2]	15.00%	Sincor	2001	2008	n/a	n/a
Venezuela: PetroCedeño [2]	9.68%	PetroCedeño	2008	2032	351	71
Africa						
Algeria: In Salah	31.85%	Sonatrach/BP/StatoilHydro	2004	2027	30	4
Algeria: In Amenas [3]	50.00%	Sonatrach/BP/StatoilHydro	2006	2022	16	8
Angola: Kizomba A	13.33%	ExxonMobil	2004	2026	29	1
Angola: Kizomba B	13.33%	ExxonMobil	2005	2027	22	1
Angola: Xikomba	13.33%	ExxonMobil	2003	2027	4	0
Angola: Marimba North	13.33%	ExxonMobil	2007	2027	2	0
Angola: Mondo	13.33%	ExxonMobil	2008	2029	8	1
Angola: Saxi-Batuque	13.33%	ExxonMobil	2008	2029	6	1
Angola: Girassol/Jasmim	23.33%	Total	2001	2022	24	0
Angola: Dalia	23.33%	Total	2006	2024	18	4
Angola: Rosa	23.33%	Total	2007	2027	12	0
Libya: Mabruk [4]	25.00%	Total	1995	2028	48	1
Libya: Murzuq [4]	2.40%	Repsol	2003	2023	104	5
Nigeria: Agbami	18.85%	Chevron	2008	2024	7	19
Europe, Caspian and Russia						
Azerbaijan: ACG	8.56%	BP	1997	2024	52	2
Azerbaijan: Shah Deniz	25.50%	BP	2006	2031	4	1
Russia: Kharyaga	40.00%	Total	1999	2032	14	2
UK: Alba	17.00%	Chevron	1994	2018	36	0
UK: Caledonia	21.32%	Chevron	2003	2018	1	0
UK: Jupiter	30.00%	ConocoPhillips	1995	2010	15	0
UK: Schiehallion	5.88%	BP	1998	2017	21	1
The Middle East and Asia						
China: Lufeng	75.00%	StatoilHydro	1997	2011	4	
Iran: South Pars	37.00%	POGC	2008	2012	30	
Total International E&P					944	127

1) Held by production
2) On 9 February 2008, Sincor in Venezuela was transformed into an incorporated joint venture known as Petrocedeño, S.A. and partially nationalized. Our share was reduced from 15% in Sincor to 9.68% in Petrocedeño.
3) Production under the terms of the In Amenas PSA commenced December 2006.
4) Renegotiations of PSAs by the NOC in Libya have resulted in a reduced equity share. Our equity share of production in Murzuq was reduced from 8.0% to 2.4% effective as of 1 January 2008. Renegotiations are ongoing for Mabruk

Country	Average daily equity production 1) mboe/day	Average daily entitlement production 2) mboe/day
North America		
Canada	22.3	22.3
USA	17.6	17.5
Latin America		
Venezuela: Sincor 3)	1.0	1.0
Africa		
Algeria	65.7	30.4
Angola	204	117
Libya 4)	11.0	5.2
Nigeria	7.7	7.7
Europe, Caspian and Russia		
Azeribaijan	100	56.4
Russia	7.7	5.7
UK	9.1	9.1
The Middle East and Asia		
China	1.7	1.6
Iran	0.8	0.8
Subtotal International E&P production	449	275
Equity accounted production		
Venezuela: PetroCedeño 3)	15.7	15.7
Total International E&P including share of equity accounted production	465	290

1) In PSA countries our shares of capital expenditures and operational expenses are computed on the basis of equity production.
2) Production figures are after deductions for royalties, production sharing and profit sharing.
3) On 9 February 2008, Sincor in Venezuela was transformed into an incorporated joint venture known as Petrocedeño, S.A. and partially nationalized. Our share was reduced from 15% in Sincor to 9.68% in Petrocedeño. As of the date of migration our share has been accounted for pursuant to the equity accounting method.
4) Renegotiations of PSAs by the NOC in Libya have resulted in a reduced equity share. Our equity share of production in Murzuq was reduced from 8.0% to 2.4% effective as of 1 January 2008. Reported volumes are after old equity share and there has been a cash settlement for the difference. Renegotiations are ongoing for Mabruk.

3.2.6 Fields in development and production

This section covers projects under development and fields in production. Pre-sanctioned projects including some discoveries in the early evaluation phase are also presented.

Exploration activities are described in report section 3.2.3, Operational review-International E&P-Exploration activity. This section often refers to a field's plateau production, which refers to yearly average equity production at plateau for a field 100% (not our share). Capacities also refer to the total field or facility, a 100% share.

The number of development wells as of 31 December 2008 for producing fields is provided under report section 3.2.5 Production above.

The total number of development wells in fields under development, that were already drilled or undergoing drilling as of year end 2008 was 127.

Project	StatoilHydro's share	Operator	Time of sanctioning	Production start
Angola: Gimboa	20%	Sonangol	2006	2009
The USA: Tahiti	25%	Chevron	2005	2009
The USA: Thunder Hawk	25%	Murphy	2006	2009
Brazil: Peregrino	100%	StatoilHydro	2007	2011
Canada: Leismer Demonstration Plant (Oil Sands phase 1)	100%	StatoilHydro	2007	2010
Ireland: Corrib	36.50%	Shell	2001	2010/2011
Angola: Pazflor	23.33%	Total	2007	2011
Angola: PSVM	13.33%	BP	2008	2012

3.2.6.1 North America

3.2.6.1.1 Canada

In Canada, oil sands represent a long term investment for the company and our Leismer Demonstration Project is on schedule. Offshore we have production from Hibernia and Terra Nova and two discoveries are under appraisal.

Oil Sands

In 2007 we acquired 100% of the shares in North American Oil Sands Corporation (NAOSC). At the time of acquisition, NAOSC owned interests in 275,213 net acres of oil sands leases located in the Athabasca region of Alberta. In its raw state, bitumen is a heavy viscous oil that we will produce using the steam assisted gravity drainage method (SAGD) from a depth of approximately 430 metres with an average producing zone thickness ranging from 15 to 30 metres.

StatoilHydro is the operator of the Kai Kos Dehseh oil sands leases, and the first phase of the development is the **Leismer SAGD Demonstration Project** which will be developed with a capacity of 20,000 boe per day with initial production scheduled for late 2010. In 2007 we submitted an application to the Alberta regulatory authorities for the full 220,000 boe per day commercial SAGD project.

In 2007 we also submitted an application to the Alberta regulatory authorities for the construction of an **upgrader** to process bitumen into lighter synthetic crude. We withdrew this application in December 2008. Prohibitive construction costs, the state of the global economy, an uncertain oil price outlook and lack of legislative clarity are the main reasons for this decision. Oil sands are a long term investment for the company with a high degree of optionality in the timing of investments.

Offshore

Discoveries Under Appraisal
The **Hebron** field was discovered in 1981. Operatorship was transferred from Chevron to ExxonMobil in 2008. A fiscal agreement was signed in August 2008 with the Government of Newfoundland and Labrador, which entails that the provincial government purchases a 4.9% equity share of the project. This reduces StatoilHydro's share in the project to 9.7% effective as of signing. The field is planned to be developed with a gravity based structure.

The **Hibernia Southern Extension** project operated by ExxonMobil comprises the development of resources in several fault blocks to the south of the existing Hibernia Main Field. Fiscal negotiations with the provincial government began in 2008 and are still ongoing.**.** The field is planned to be developed via drilling from the Hibernia GBS platform. We have 10% interest in this field.

StatoilHydro's activities in Newfoundland include an interest in the offshore field Terra Nova.

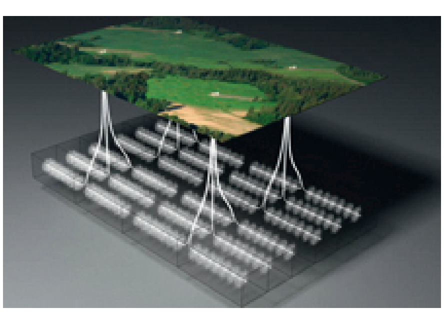
Fields in production
Hibernia was developed with a GBS and is operated by ExxonMobil. Production started in 1997 and the field is currently producing from 55 wells.

Terra Nova is producing from a floating production, storage and offloading vessel (FPSO), operated by Petro-Canada. Fifteen subsea producing wells are tied back to the FPSO. Terra Nova's production efficiency continues to be low due to a number of technical issues on the FPSO. Several initiatives are underway to improve production efficiency.

3.2.6.1.2 The USA

We have built a high quality deep water asset portfolio in the Gulf of Mexico by combining acquisitions and exploration. In 2008 we expanded into onshore gas through a 32.5% interest in Chesapeake Energy Corporation's Marcellus shale gas acreage.

We also formed a strategic alliance with Chesapeake to jointly explore unconventional gas opportunities worldwide.



Marcellus shale gas development with several well pad sites.

Onshore
The **Marcellus Shale Gas** play is located in the Appalachian region of the northeastern USA. In November 2008 we acquired a 32.5% interest in Chesapeake's Marcellus shale gas acreage. Production started in 2008 and drilling of new wells will continue in 2009. We also have the right to a 32.5% participation in additional Chesapeake leases in the Marcellus Shale play.

Independence Hub GoM.

Offshore, Gulf of Mexico

Discoveries under appraisal, Gulf of Mexico

The **Jack** oil field in which we have a 25% interest is located at Walker Ridge 758/759. Jack is operated by Chevron and was discovered in 2004. In 2008 we drilled another appraisal well.

St. Malo, located at Walker Ridge 678, is also an oil field operated by Chevron. We have 6.25% interest in St. Malo. In 2008 we drilled another appraisal well. St. Malo and Jack are in approximately 2,100 metres of water and separated by approximately 40 kilometres. The current plan is a joint development of the two fields and Chevron has formed a joint integrated project team for this purpose. In 2009 we plan to make a concept selection for the development of the two fields and to start front-end engineering and design.

We have a 27.5% interest in **Big Foot** which is a Chevron-operated discovery located in WR29. During 2008 appraisal drilling took place and will continue into 2009. We expect to make a concept selection in 2009.

The **Caesar** unit in which we have a 23.55% interest is operated by Anadarko and covers blocks GC683 and some surrounding blocks, including the **Tonga** discovery. A joint development is planned for Caesar and Tonga and the selected concept is a 4-well subsea tieback to the Anadarko-operated Constitution platform. During 2008 an appraisal well was drilled.

Fields under development

We have a 25% interest in the Chevron operated **Tahiti** field, located at Green Canyon 640. The Tahiti development consists of a Spar production platform connected to two subsea drill centres with production capacity of 125,000 bbl per day. Production on Tahiti is expected to start mid 2009.

In **Thunder Hawk** we have a 25% interest and Murphy is the operator. It is located at Mississippi Canyon 734. The field is being developed with a floating semi-submersible platform tied in to a third party processing facility in Mississippi Canyon 736. The processing capacity is expected to be 45,000 bbl of oil per day.

Fields in production

Our three **Eastern Gulf** deepwater natural gas fields are tied back to the Anadarko-operated Independence Hub. The three fields are the StatoilHydro operated Q field, in addition to partner operated San Jacinto and Spiderman. The fields are producing via subsea tiebacks to the Independence Hub platform, a floating production facility on Mississippi Canyon Block 920. The Independence Hub is owned by third parties and has a processing capacity of one billion cubic feet of natural gas per day. We own 12.7% of the capacity of the hub. In the spring of 2008, the Independence Hub experienced an unexpected shut-down for two months due to a leak in the export pipeline. The leak was successfully repaired during the summer of 2008. Production was also shut down during Hurricanes Gustav and Ike, but no significant damage was done to the facility or the pipelines.

Lorien, located at Green Canyon 199, produces through a two-well subsea tie-back to Shell's Bullwinkle platform. Following Hurricanes Gustav and Ike, Lorien was shut-down due to damage to Bullwinkle. Production resumed in January 2009.

The Murphy-operated **Front Runner** field is located in Green Canyon 338/339. Production in 2008 has been relatively stable. However, due to complex geology with relatively weak reservoir communication, the production from Front Runner has been significantly lower than expected at production start in 2004. The gas-export line was damaged by Hurricane Ike. Gas export resumed in January 2009.

We also had production in 2008 from two small deepwater fields called **Zia and Seventeen Hands.** They are located at Mississippi Canyon 496 and 299, respectively.

3.2.6.2 Latin America

Our current asset portfolio in Latin America comprises our interest in the heavy oil Peregrino development project in Brazil and an onshore extra heavy oil producing asset, the Petrocedeño Mixed Company, in Venezuela.

The Petrocedeño Mixed Company was formerly known as the Sincor project.
We also have a representative office in Mexico City.

3.2.6.2.1 Venezuela

StatoilHydro has a long term view on its presence in Venezuela and has a 9.677% interest in the Petrocedeño project.

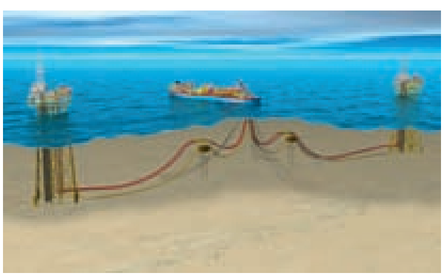
The Petrocedeño project involves the exploitation of extra heavy crude oil from the reservoirs in the Orinoco Belt. A diluting component is added in order for the extra heavy oil to be transported by pipeline to the coast where it is upgraded to a light, low-sulphur syncrude, destined for the international market. Petrocedeño, S.A., owned by the project partners, operates the field and is responsible for the development, operation, upgrading and marketing of its products.

In 2008 the Sincor project was transformed into an incorporated joint venture named Petrocedeño, S.A., which became operational starting from 9 February 2008. Our share was reduced from 15% in Sincor to 9.677% in Petrocedeño.

A major maintenance turnaround was carried out in early part of 2008. The maintenance tasks were performed as planned, although some of the important modification projects were postponed to 2009. During the turnaround, a much higher volume of extra heavy oil was produced than originally planned and marketed as diluted crude oil.

3.2.6.2.2 Brazil

In 2008, we acquired Anadarko's remaining 50% share of the Peregrino oil field and became 100% owner and operator. By 2012 StatoilHydro is expected to become the largest international offshore operator in Brazil in terms of production.



Peregrino.

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

The field is being developed with a Floating Production Storage and Offloading Vessel (FPSO) and two well head platforms with drilling capability. The first oil production is planned to come on stream in 2011 and we expect to reach a plateau production of 100 mboe per day within the first year of production**.** All development contracts have been entered into and the execution phase of the project is in progress.

3.2.6.3 Africa

We have interests in onshore producing assets in the North African countries of Algeria and Libya.

Our current development and production portfolio in Sub Saharan Africa comprises blocks 4/05, 15, 17 and 31 offshore Angola, and the production licences OML 127 and OML 128 offshore Nigeria.

3.2.6.3.1 Algeria

Our main asset, In Salah, gives us a considerable gas position in Algeria. We are also producing liquids from the In Amenas field.

Fields in production
The **In Salah** onshore gas development in which we have a 31.85% interest is Algeria's third largest gas development. The field is currently producing at plateau level. A Contract of Association, including mechanisms for revenue sharing, governs the rights and obligations of the joint operatorship between Sonatrach, BP and StatoilHydro. A joint marketing company sells the gas produced in the development, and all gas produced until 2017 has been sold under long-term contracts.

In addition to the operating activities at In Salah, drilling operations and a compression expansion project have been ongoing in 2008. The activities in 2009 will include startup of some of the compression stations and further work on preparing for the In Salah Southern Fields development. StatoilHydro is in charge of the compression project.

The **In Amenas** onshore development is the fourth largest gas development in Algeria, containing significant liquid volumes. The development was built and is operated through a joint operatorship between Sonatrach, BP and StatoilHydro, and we have a 50% share of the development costs. This project is currently producing at plateau level. The rights and obligations are governed by a production sharing contract, giving BP and StatoilHydro access to a share of the liquid volumes only. A continuous production drilling campaign is ongoing. Further preparations and maturing of the In Amenas Compression Expansion project is ongoing and will continue in 2009 with BP as lead.

The overall security and political situation continues to be sensitive and is monitored continuously. Appropriate measures are assessed based on the perceived risk level. This risk monitoring will continue through 2009.

3.2.6.3.2 Libya

We are well positioned for growth in Libya with two producing assets and our focus on technology-based IOR projects.

Fields in production
The **Mabruk** oil field is located in licence C-17, north-west in the Sirte basin and is developed in phases.

A Field Development Plan (FDP) for Mabruk Phase I (previously denoted phase V), covering the Dahra South East is expected to be approved by the Libyan National Oil Corporation (NOC) in 2009.

The NC 186 licence in the **Murzuk** area consists of several fields. We are producing from the A, B, D and H fields which were developed with one common processing facility. The oil from these fields is blended with oil from the neighbouring licence NC 115 and is then transported by pipeline to the Az Zawia terminal west of Tripoli.

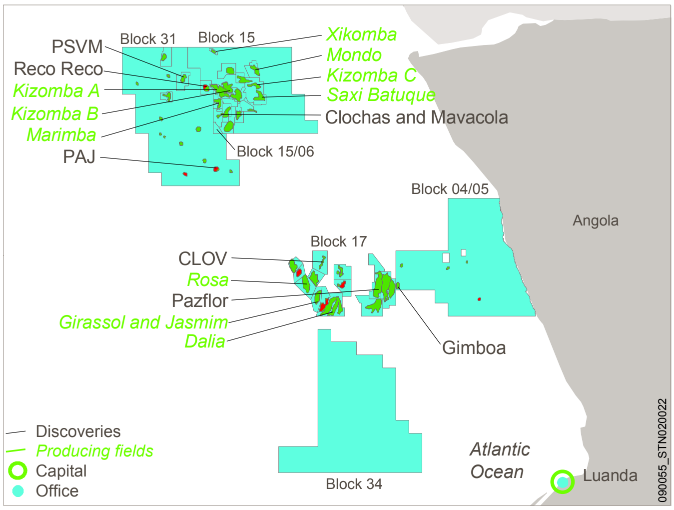
The I/R oil field, which straddles across both the NC 115 and NC 186 licenses, started production in June 2008.

A FDP for the J and K fields was approved by both the partnership and NOC. The fields are expected to start production in 2010.

To avoid extensive flaring from the NC 186 fields, a gas utilization project is ongoing, with the aim of using the associated gas from the oil production for electricity generation. Start-up of the project is expected in 2009, when planned flaring in the 186 area will be eliminated.

3.2.6.3.3 Angola

The Angolan continental shelf is the largest contributor to StatoilHydro's production outside Norway. It yielded 117 mboe per day in entitlement production at the end of 2008, 40% of our total international oil and gas output.



FPSO vessels with subsea wellheads are the preferred oil-field development solution in deepwater Angola due to the great water depths, high production volumes and lack of infrastructure.

Block 17 is operated by Total and our interest is 23.33%. Production from the block currently comprises the Girassol, Jasmim, Dalia and Rosa development areas. The Girassol and Jasmim development areas both produce over the Girassol FPSO. The plateau production level, reached in 2005, was 250 mboe per day. The second FPSO, Dalia, has been producing at peak level of 240 mboe per day in 2008. Rosa is a tie-back field to the Girassol FPSO. The combined production on the Girassol FPSO has a capacity limit of 280 mboe per day.

The Pazflor project comprises the discoveries Perpetua, Acacia, Zinia and Hortensia. Pazflor was sanctioned in 2007. The FPSO is expected to have a production capacity of 200 mboe per day, with start-up scheduled in 2011.

The installed production capacity on block 17 will be approximately 700 mboe per day, after Pazflor starts production.

Work is ongoing to pursue the common development of four additional discoveries, Cravo, Lirio, Orchidea and Violeta (CLOV).

The Gas Export Project (GEP)
According to the PSA, all surplus gas from the offshore blocks is to be delivered to Sonangol who owns the gas. Block 17 is progressing on a Gas Export Project which is split into two phases. Phase I, which was sanctioned in 2007, comprises an export line from Block 17 to Block 2 where the gas can be injected through a wellhead platform if Angola LNG (AnLNG) for some reason is unavailable. Phase II includes a 24-inch diameter pipeline from Block 2 to AnLNG, and was sanctioned in July 2008. Costs related to the development will be recovered through the PSAs.

Block 15 is operated by ExxonMobil and our interest is 13.33%. Production from the block currently comprises five FPSOs for Kizomba A, Kizomba B, Xikomba, Kizomba C-Mondo and Kizomba C-Saxi Batuque. Mondo and Saxi-Batuque came on stream on 1 January and 1 July 2008 respectively.

Kizomba A, which encompasses the Hungo and Chocalho discoveries, commenced production in 2004. Marimba North is a tie-back to the Kizomba A FPSO. The peak production limit on the FPSO was then increased to 270 mboe per day, of which Marimba North produces 35 mboe per day. Kizomba B encompasses the Kissanje and Dikanza discoveries. Kizomba A and Kizomba B came off plateau during 2008. Xikomba is a small, isolated discovery producing from a leased FPSO. The combined Kizomba C production has already reached plateau levels of 200 mboe per day in 2008.

According to the PSA, all surplus gas from the offshore blocks is to be delivered to Sonangol. The Gas Gathering Project for Block 15 will collect all surplus gas from Kizomba A, B and C including satellites. The trunkline will connect to AnLNG piping going to AnLNG.

Work is also ongoing to pursue the development of two medium-sized discoveries: Clochas and Mavacola, which are called Kizomba Satellites Phase 1.

Block 31, an ultra-deep water licence, is operated by BP, and our interest is 13.33%. The common development of the first four discoveries in the northern part of the block, Plutao, Saturno, Venus and Marte (PSVM) was approved by the Concessionaire in July 2008. The PSVM will be developed via a new FPSO with a production capacity of 150,000 boe per day.

Work is also ongoing to pursue the development of PAJ, comprising the discoveries Palas, Astraea, and Juno.

Two to four additional production hubs are expected to be launched in this block.

Block 4/05 is operated by Sonangol P&P and our interest is 20%. This block includes the Gimboa field which was sanctioned in 2006. Peak production from the field is expected to be 35 mboe per day and the FPSO is expected to commence production in first half of 2009.

Work is also ongoing to pursue the development of Gimboa Phase 2, two small-sized discoveries, UMC-6 and UMC-7.

3.2.6.3.4 Nigeria

In Nigeria, we have an interest in the largest deepwater producing field, Agbami.

Agbami FPSO.

The **Agbami** field in deep waters off Nigeria has been developed with subsea wells connected to an FPSO. Production started up on 29 July 2008. Agbami, operated by Chevron, is located in licences OML 127 and OML 128, approximately 110 kilometres off the Nigerian coastline. Our interest in the unitised field is 18.85%. The Agbami field is expected to reach a plateau production of 250 mboe per day by late 2009.

There is renewed vigor by the Nigerian government to restructure the oil and gas sector. StatoilHydro is following the developments in the country. So far it is not possible to determine the impact of a potential regulation restructure.

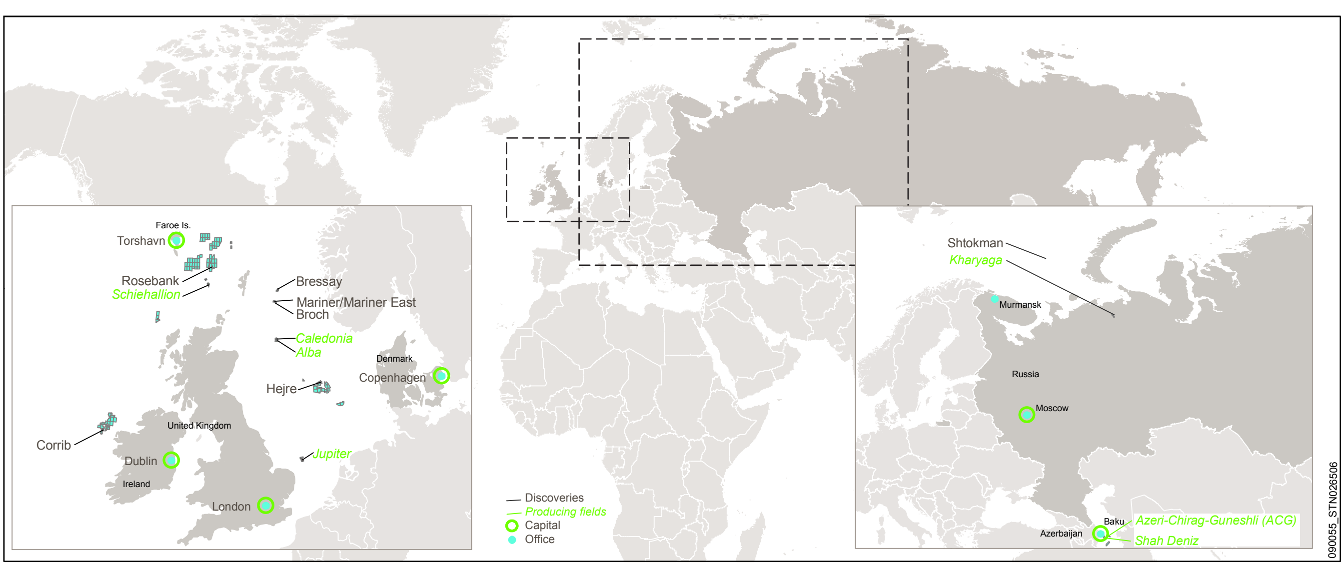
With the Supreme Court judgement on the validity of the 2007 presidential election still being awaited, the political situation remains unstable, but there has been an improvement in the security situation in the strategically important oil region in the Niger Delta. The overall security and political situation is monitored continuously. We have developed rigorous security measures to protect our personnel and other assets. Appropriate measures are continuously being assessed based on the perceived risk level.

3.2.6.4 Europe, Caspian and Russia

We have interests in production and development assets in Ireland, the United Kingdom, Azerbaijan and Russia in addition to early phase evaluation assets in the United Kingdom and Denmark.

The Russian Shtokman field is an important part of our strategy to pursue opportunities in harsh arctic environments. Our ambition is to continue to build on our portfolio whilst pursuing opportunities to improve on the production and cost performance of our current producing assets, and bring existing discoveries through to development.

We also have representative offices in Kazakhstan and Turkmenistan.



3.2.6.4.1 United Kingdom

StatoilHydro has been present in the United Kingdom (UK) since the early 1980s. We hold interests in four producing fields, Alba, Schiehallion, Jupiter and Caledonia and have several oil fields under appraisal, Bressay, Mariner, Mariner East and Rosebank.

Discoveries under appraisal
We are operator for Bressay (in which we have a 81.63% interest), Mariner (in which we have a 44.44% interest) and Mariner East (in which we have a 62% interest). These are all heavy oil discoveries where further studies and appraisal will continue. Current development plans for both fields consist of a fixed steel jacket with drilling, processing and quartering facilities.

Rosebank (in which we have a 30% interest), a discovery made by Chevron in 2004, is located west of the Shetland Islands. The operator is currently drilling further appraisal wells.

Fields in production
The Alba field commissioned in 1994 is located in the central part on the UK North Sea and operated by Chevron. We have 17% interest in Alba.

Schiehallion, commissioned in 1998, is a floating, production, storage and offloader (FPSO) located west of the Shetland Island, and the operator is BP. We have 5.88% interest.

Jupiter is a gas field located in the southern part of the UK North Sea in which we have 30% interest. The operator is ConocoPhillips.

Caledonia is a small single well tie-back to the Britannia platform in the central part of the North Sea in which we have 21.32% interest, and where the operator is Chevron.

All fields are in a mature to late life stage of production.

3.2.6.4.2 Ireland

We have 36.5% interest in the Corrib gas field which lies on the Atlantic Margin north-west of Ireland. The Corrib field development, operated by Shell, was sanctioned in 2001 and production start-up is currently expected at the end of 2010 or early 2011.

The development will comprise seven subsea wells, and the gas will be transported through a pipeline to an onshore gas processing terminal. The gas will be exported from the terminal via the Bord Gais Eireann linkline to the existing Irish gas grid.

The Irish planning authorities granted planning permission for the gas terminal in 2004. Project execution was suspended in 2005 due to protests by local landowners. Following a comprehensive safety review of the onshore pipeline by the Irish authorities, work on the project recommenced in 2006. As part of a community consultation process, alternative pipeline routes have been identified, and the final planning application for the onshore pipeline is expected to be made in the second half of 2009. Currently, six of the seven offshore wells have been drilled. Construction of the gas terminal commenced in 2007 and is ongoing.

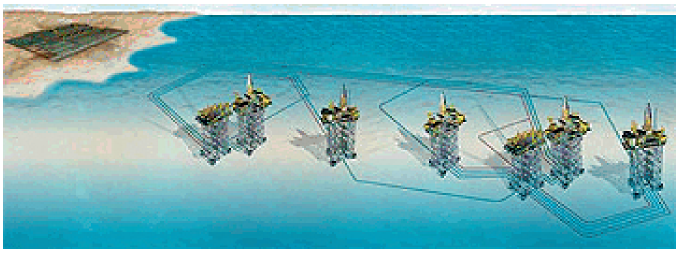
3.2.6.4.3 Denmark

In the Danish sector of the North Sea we are a partner in the Hejre field, an undeveloped oil field.

Discoveries under appraisal
We have a 25% interest in the **Hejre** oil field, operated by Dong, in licence 5/98 located in the Danish sector of the North Sea. The partnership is in the concept evaluation phase.

3.2.6.4.4 Azerbaijan

StatoilHydro has been present in Azerbaijan since 1992. Since then, we have entered into three PSAs in Azerbaijan, and we are among the largest foreign oil companies in the country in terms of proved reserves and production.



Azeri Chirag Gunashli (ACG) platforms.

At present, we hold interests in three PSAs offshore in the Azeri sector of the Caspian Sea: the Azeri-Chirag-Gunashli (ACG) oil field, the Shah Deniz gas and condensate field and the Alov, Araz and Sharg prospects described in the report section 3.2.3.4.2 Operational review-International E&P-Exploration activity-Europe, The Caspian Region and Russia-Azerbaijan.

We have an 8.5633% interest in the BP-operated **ACG** PSA. Production from the field commenced in 1997. The field has subsequently been developed through the ACG Phase I-III developments, which were brought on stream in the period 2005 to 2008. Additional production through the Chiraq Oil Project is expected to commence in 2013.

A gas leak originating underground was detected on the seafloor beneath the Central Azeri platform in the third quarter of 2008 and production from the platform was temporarily shut down. Although limited production from Central Azeri was resumed in December 2008, the gas leak is expected to have a negative effect on the production from ACG throughout 2009.

Export of hydrocarbons. Currently, crude oil from ACG is transported to the Mediterranean Sea through the 1760 kilometres Baku-Tbilisi-Ceyhan (BTC) Pipeline, in which we participate with an 8.71% interest. In August 2008, a fire occurred at a pipeline bolt. However, the impact on production from ACG was limited and the pipeline was brought back in operation three weeks after the incident. In the fourth quarter of 2008, the BTC Pipeline had an export capacity of more than 900 mbbl of oil per day.

The **Shah Deniz** area covers 860 square kilometres and lies at a water depth of between 50 and 500 metres. BP is the field operator and we have a 25.5% interest. We are the operator of the AGSC company covering gas sales, contract administration and business development for the Shah Deniz stage I. We are also the commercial operator of the South Caucasus Pipeline system (SCP) for gas transport to markets in Azerbaijan, Georgia and Turkey.

Shah Deniz Stage I commenced production in December 2006. The Stage 2 development of Shah Deniz is progressing through the investment decision process and is presently in the concept selection stage. Field reserves support a significant Stage 2 development which is likely to be on a similar or larger scale to Stage 1.

The Caspian region has long been viewed as an area with a substantial risk of increased economic, social and political instability. Although the general situation has improved, there are still political disputes that remain unsolved in both Azerbaijan and Georgia, and the recent events in Georgia show that the risks should not be underestimated.

3.2.6.4.5 Russia

StatoilHydro has been present in Russia since the early 1990s. We have one producing field, the Kharyaga oil field, and a 24% ownership share in Shtokman Development AG responsible for the Shtokman development phase I.

The Shtokman gas and condensate field is located in the Russian Barents Sea, and the Shtokman agreement gives StatoilHydro a 24% equity interest in Shtokman Development AG in which Gazprom (51%) and Total (25%) are the other two partners. The owners have seconded personnel to Shtokman Development AG, which is responsible for planning, financing, constructing and operating the infrastructure necessary for the first phase of the development. Shtokman Development AG will own and operate the infrastructure for 25 years from the start of commercial production. The implementation of the project is subject to a final investment decision which is planned to take place in 2010.

Field in production

The **Kharyaga** field is located onshore in the Timan Pechora basin in North West Russia. We have 40% interest and Total is the operator.

The Kharyaga field will be developed in stages according to the terms of the PSA. Oil production commenced in 1999, with **Phase 1** production of 10 mboe per day utilising three existing wells. **Phase 2** was launched in 2000 to increase oil production and develop additional reserves. An additional 11 wells were drilled during this phase. **Phase 3** has now been initiated with the aim of increasing production from 20 to 30 mboe per day. This phase involves drilling of more production and injection wells, a process upgrade and installation of gas treatment facilities.

3.2.6.5 The Middle East and Asia

StatoilHydro has interests in the South Pars project in Iran and the Lufeng field offshore China.

We are also pursuing business development opportunities in the region, and have representative offices in Indonesia, Singapore and Australia and in selected countries in the Middle East. We are also qualified as "Non-restricted Operator" in Iraq and may thereby tender as operator for any field in the two upcoming licence rounds in the country in 2009.

3.2.6.5.1 Iran

Gas production from South Pars Phase eight started in August 2008 and from Phase six in December 2008. Production from the third and final phase, South Pars Phase seven, is expected to commence after the summer of 2009.

StatoilHydro entered the South Pars project in 2002 as operator for the development of the offshore part of the **South Pars Phases six, seven** and **eight** under a buy-back contract with a 37% share during the development phase. Upon completing the development phase, StatoilHydro's obligation includes providing certain services to the National Iranian Oil Company (NIOC) during the operations phase; however, our involvement will be phased out once we have recouped our costs for the project.

Based on the two discoveries on the **Anaran** block, Azar and Changuleh, StatoilHydro discussed a Development Service Contract with NIOC.

StatoilHydro has an exploration and development service contract with NIOC for the **Khorram-Abad** block in Lurestan province in south-western Iran. The block covers 7400 square kilometres, and the work programme includes acquisition of 600 square kilometres of 2D seismic data and the drilling of three exploration wells. The gathering of seismic data was completed in the fourth quarter of 2008. There are at present no firm plans to drill the first well in the work programme.

See report section 5.1.1 Risk review - Risk factors- Risks related to our business, for additional information concerning the risk of US sanctions related to activities in Iran.

The Company will not make any future investments in Iran under the present circumstances; however, it is committed to fulfilling its buy-back contract obligations, principally for the offshore part of the South Pars phases six/seven/eight project.

3.2.6.5.2 China

StatoilHydro opened its first office in China in 1982. Today, our activities involve operating the Lufeng field and business development.

Lufeng will probably be shut down during 2009.

In 2007 StatoilHydro entered into a strategic partnership with China National Petroleum Corporation ("CNPC") through the signing of a Memorandum of Understanding relating to domestic and international exploration and production, LNG value chain and research and development. This cooperation has now been expanded to also cover new energy.

3.3 Natural Gas

3.3.1 Industry overview

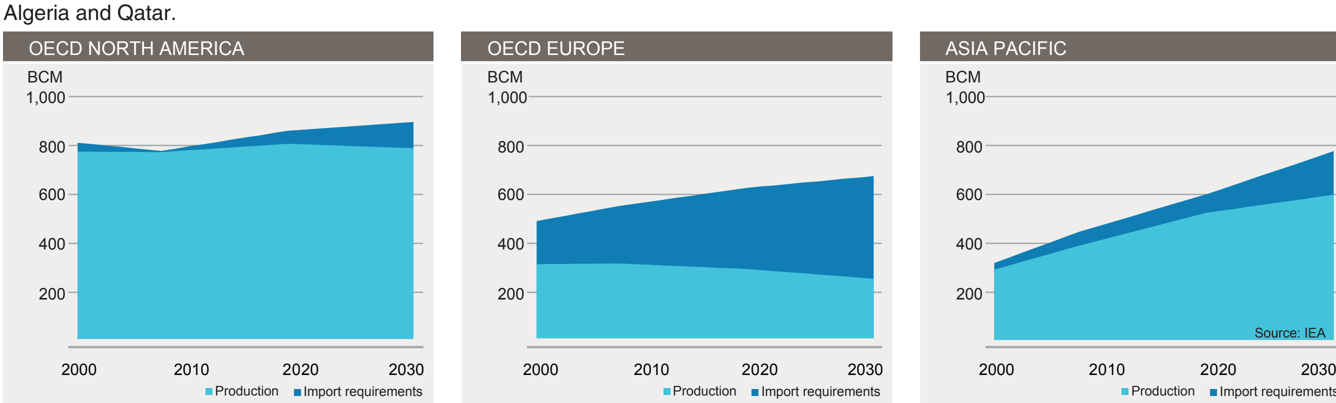
Fossil fuels will continue to be the prime source of incremental energy supply for several decades to come - and natural gas is expected to continue to be the fastest growing fossil fuel in OECD markets.

According to the International Energy Agency's (IEA) World Energy Outlook for 2008, fossil fuels will continue to be the prime source of incremental energy supply in the decades ahead. However, on a regional level, the growth in demand for specific fuels will vary. In developing countries, coal is expected to see the fastest growth in demand, whereas natural gas is expected to continue to be the fastest growing fossil fuel in the OECD markets.

In the IEA reference scenario, the world primary demand for natural gas will expand by just over half between 2006 and 2030, to 4,400 bcm, a rate of increase of 1.8% per year. The share of natural gas in total world primary energy demand is expected to increase to 22% in 2030. Some 57% of the projected increase in gas demand comes from the power sector, pushing up its share of global gas use from 39% today to 45%. Inter-regional gas trade is projected to more than double towards 2030, from 441 bcm in 2006 to more than 1000 bcm in 2030. The European Union expects the biggest increase in import volumes.

Natural gas can substitute for other fuels in almost any application. In many global scenarios for the mitigation of climate change, there is an implicit assumption that gas use will increase. Thus, future demand for natural gas looks robust and sustainable, assuming that the necessary regulatory and competitive frameworks are established.

On the supply side, there is major concern over possible energy deficits (or "gaps") in several main gas-producing countries. In consequence, international natural gas markets will be influenced by policy decisions in key producing and reserve holding countries such as Russia, Iran, Algeria and Qatar.



From around 2010, it is expected that Europe will need additional supplies of piped gas and/or LNG in order to cover demand. Gas from the NCS is attractive in the European market due to its high regularity and geographical location. We therefore expect that demand for gas from Norway will continue to increase in our primary gas markets, as domestic gas production elsewhere in Europe continues to decline.

The international gas industry is driven by several trends that have implications for our business:

- Accelerated growth in energy demand driven by population and economic growth, with natural gas playing a more important role in the energy mix. The IEA expects the current economic setback to be reversed by the end of 2009, with demand drivers for additional energy picking up again.
- Due to increased import dependency, natural gas will be transported over increasingly long distances, both as LNG and via pipelines.
- Environmental concerns and climate change policies are becoming more important.
- Major resource-holding countries will have an even stronger impact on the global supply picture for gas.
- Gas and power markets will continue to converge, especially in mature markets such as the OECD.

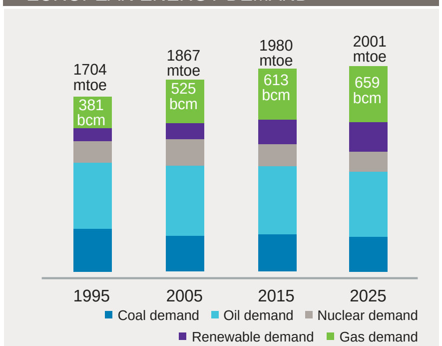
These trends and developments indicate new opportunities for our gas business. While robust demand will continue to underpin the longer term supply business, increased transparency, connectivity and liquidity in the market place will open up new areas for value creation through optimisation and trading. Hence, our gas strategy aims to continue to strengthen the long-term supply business while at the same time grasping new business opportunities as market developments allow.

3.3.2 European gas market

According to the IEA World Energy Outlook 2008, the estimated annual growth in global gas consumption in the period 2006 to 2030 will be 1.8%, slightly less than the estimate from last year.

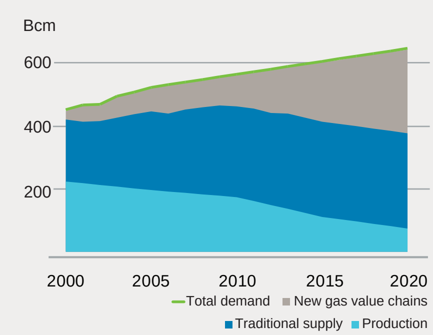
Growth in gas demand in OECD Europe in the same period is expected to be 1.0% per annum. This translates to a demand for gas in OECD Europe in 2030 of approximately 694 bcm - up from the current level of some 550 bcm. The share of gas in total primary energy consumption is approaching 25% in the OECD countries in Europe, and is expected to reach almost 30% in 2030. Approximately 60% of the growth in gas consumption in the period is expected to come from the electricity sector. The IEA expects continued growth in demand for all sub-sectors of the European natural gas market.

EUROPEAN ENERGY DEMAND



Source: IEA WEO 2008 Reference Scenario World, OECD Europe

OECD EUROPE - SUPPLY SOURCE



Sources: IEA, Wood Mackenzie

We market and sell our gas together with the Norwegian State's natural gas. We are the second largest gas supplier in Europe and the sixth largest supplier in the world. Furthermore, we market gas sourced from producing areas other than the NCS. Other major gas suppliers in Europe are Gazprom in Russia, Sonatrach in Algeria and Gasunie in the Netherlands. We believe that the Norwegian natural gas exports will remain highly competitive due to their reliability, access to the transportation infrastructure and proximity to key European markets such as the UK, Germany and France. In addition, natural gas is an attractive source of energy from an environmental perspective since it emits far less CO_2 than coal and oil.

For a long time, the UK was the second largest producer of natural gas in Europe after Russia. However, by 2016 it is expected that the UK may be dependent on imports for approximately 80% of its gas requirements. Based on our growing infrastructure, we believe we are well positioned to supply a portion of the UK's additional demand for imported natural gas and to become more involved in the UK market - Europe's largest and most liberalised natural gas market.

Langeled, a new export pipeline, was put into operation in 2007, connecting the NCS to Easington in the UK. Another new infrastructure project called the Tampen Link, a pipeline from the Statfjord field on the NCS to the existing Flags pipeline on the UK continental shelf, was also completed in 2007.

The recent dispute between Russia and Ukraine regarding gas transit highlighted the importance of Russian gas supplies to European markets. In the years ahead Russian supplies are expected to grow further, and in the longer term the EU is set to import some 80% of its natural gas. In order to diversify supplies, European countries and companies are actively seeking to establish alternative supply solutions, mainly through LNG, but also by establishing new pipeline infrastructure from the Caspian region and from North Africa.

We believe that Europe will need additional sources of natural gas. We are participating in increasing gas production in Azerbaijan, with the Shah Deniz field in the Caspian Sea as a key asset. Gas is already exported from Azerbaijan to Georgia and Turkey through the South Caucasus Pipeline (SCP). In order to bring gas even further west we are participating in the Trans-Adriatic Pipeline (TAP) that will connect the Italian market with gas flowing westwards from Turkey, through Greece and Albania.

As the European energy market undergoes deregulation and structural changes, we believe that natural gas will play an increasingly important role. This trend will be reinforced by additional steps in Europe to curb carbon dioxide emissions, in particular by the use of carbon pricing mechanisms such as the EU Emission Trading Scheme. We expect the use of natural gas as a source of electricity generation to continue to grow, as there is a need to replace even more coal-based generation capacity with natural gas. Deregulation opens new opportunities and business models in the gas sector, both with regard to added values through efficiency gains and to building a more substantial end user sales portfolio. The integration of the gas and power markets also presents us with new business opportunities in trading and as a means of increasing the value of gas by upgrading through generation and improving our flexibility in market operations. We therefore aim to manage and further develop marketed volumes, and to increase the scale and scope of our trading, optimisation and midstream and downstream activities.

For information about the EU Gas Directive, please see report section 3.10.3 Operational review-Regulation-Gas directive of the European Union.

3.3.3 Gas sales and marketing

StatoilHydro is a long-term and reliable natural gas supplier enjoying a strong position in some of the world's most attractive markets. We are the second biggest gas supplier in Europe and the sixth largest in the world.

Europe
The major export markets for NCS gas are Germany, France, the United Kingdom, Belgium, Italy, the Netherlands and Spain. Our main customers are large national or regional gas companies such as E.ON Ruhrgas, Gaz de France, ENI Gas & Power, British Gas Trading (a subsidiary of Centrica), Distrigaz and Gasunie. In addition, we sell to large end users, mostly through long-term take-or-pay contracts.

In the United Kingdom, we market our gas to large industrial customers, power generators and wholesalers, in addition to participating in the UK spot market. NG also has an end user sales business based in Belgium, serving large customers in Belgium, the Netherlands and France. Our group-wide gas trading activity is mainly focused on the UK gas market, which is a significant market in terms of size and the most liberalised market in Europe. We are also increasingly taking part in other liquid trading points such as the TTF (Title Transfer Facility) in the Netherlands and at Zeebrugge Hub in Belgium.

In 2004, Statoil (UK) Limited and SSE Hornsea Limited (subsidiaries of StatoilHydro and Scottish and Southern Energy Plc, respectively) entered into a joint venture for the development, operation and maintenance of a salt cavern gas storage facility near Aldbrough, on the east coast of Yorkshire and close to the Easington terminal. On completion, the storage facility will comprise nine underground caverns. Statoil (UK) Limited owns one third of the storage capacity being developed, of which the SDFI has a 48.3% share. The facility has been developed and will be operated by SSE Hornsea Limited. The storage facility is expected to begin commercial operation during 2009, with full commercial operation of the nine cavern facility achieved during 2011. The design capacity for the storage facility is expected to be 420 mmcm. StatoilHydro's share of the total development cost is estimated to be NOK 0.7 billion.

In Germany, we hold a 30.8% stake in the Norddeutsche Erdgas-Transversale, or Netra, overland gas transmission pipeline, and a 23.7% stake in Etzel Gas Storage through our subsidiary StatoilHydro Deutschland. Currently, Etzel Gas Storage is increasing the working gas capacity with nine additional caverns. All partners in Etzel Gas Storage are participating in this project. The project is expected to be finalised within the calendar year 2009, according to schedule.

Cove Point. Cove Point with the additional capacity almostfinalised and Arctic Princess discharging at the pier.

US
In the US, Statoil Natural Gas LLC (SNG) markets gas to local distribution companies, industrial customers and power generators. We have a long-term contract with the operator of Cove Point, Dominion Resources Inc., securing us capacity rights of 2.4 bcm per year at the Cove Point regasification terminal in Maryland on the US east coast. The terminal interconnects with three interstate pipelines, allowing gas to be directed to the Mid-Atlantic and North-East markets. The SDFI participates with a 56.5% share of our capacity in the terminal and pipeline. LNG is sourced from our Snøhvit LNG facilities in Norway and from third party suppliers, both spot and mid-term arrangements. In 2008 we delivered cargo number 100 of LNG to the Cove Point terminal. SNG also markets the equity production from our assets in the US Gulf of Mexico in addition to sourcing some pipeline gas domestically, mainly for optimisation purposes.

In 2005 StatoilHydro entered into contractual commitments with Dominion for 100% of the expansion of the Cove Point terminal with a capacity of approximate 7.7 bcm annually of gas for a 20-year period, with planned start-up in early 2009. The expansion reflects our focus on the growing liquefied natural gas market in the US, at the same time as market access through Cove Point is strategically important to a potential Snøhvit phase 2 and other LNG projects under consideration by StatoilHydro. In addition it gives us more flexibility in sourcing third party LNG to the terminal.

The respective future shares of StatoilHydro and the SDFI on the Cove Point terminal, in addition to extra capacity and related commitments, are subject to further consideration, and the outcome may therefore have an impact on the extent of future commitments assumed and reported by StatoilHydro.

In 2008 we entered into a strategic agreement with Chesapeake Energy Corporation. The agreement is particularly important for NG in several ways. Firstly, it adds a major building block to our gas value chain position already established in the US - the world's largest and most liquid gas market, and secondly, we gain access to large reserves produced close to the highest paying market in the US. Also, it significantly strengthens our US gas position, building on our existing Cove Point LNG position and our well-established gas marketing and trading organisation in Stamford and the competence in our organisation. The agreement entails that over time, we will market and trade significantly higher volumes compared to the volumes today.

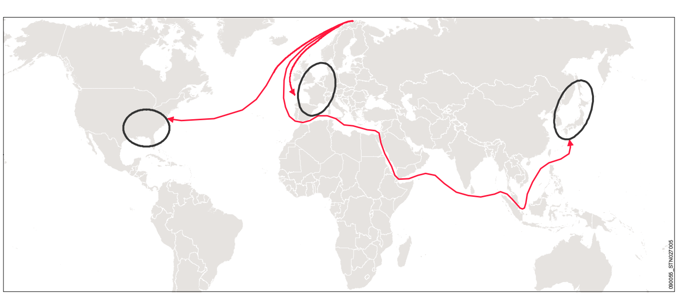
Azerbaijan

Shah Deniz transportation solutions. TAP, Nabucco and IGI are all proposed pipeline transportation solutions for the Shah Deniz stage 2 gas to the European market.

StatoilHydro has a 25.5% share in the Shah Deniz field in Azerbaijan and is the commercial operator for gas transportation and sales activities for Stage 1 development and heading the partners sales committee for the Stage 2 development. Turkey is the main market for gas from Stage 1 of the Shah Deniz development, and in addition Georgia and Azerbaijan are also part of the gas sales portfolio. Gas is transported to customers through the South Caucasus Pipeline (SCP) running from Azerbaijan via Georgia to the Georgian/Turkish border. Shah Deniz Stage 1 production and the related gas transport in SCP were ramped up throughout 2008 and is expected to reach the plateau production in 2009 (8.6 bcm annually).

The Stage 2 development of Shah Deniz is currently in the Concept Selection phase of the operator BP's Capital Value Process. Field reserves support a significant Stage 2 production and are likely to be larger than in Stage 1. Key activities for NG in this respect are related to the commercialisation of Stage 2 through organisation, planning and conduct of gas market/transport evaluations and negotiations with counterparties in the Caspian region, Turkey, the European Union and Russia. The progress of the marketing activities has been hampered by the lack of an intergovernmental agreement between Turkey and Azerbaijan on volumes for transit and sales into the Turkish market.

In February 2008, StatoilHydro signed an agreement with the Swiss EGL Group to establish a joint venture to develop, build and operate the Trans Adriatic Pipeline (TAP) from Greece, through Albania to Italy. StatoilHydro joined the TAP project as part of our efforts to provide attractive export options and ensure competition for the Shah Deniz gas in the European market, hence TAP will be competing with other pipelines to attract potential customers for gas from Shah Deniz. A final investment decision is linked to the Shah Deniz Stage 2 development.



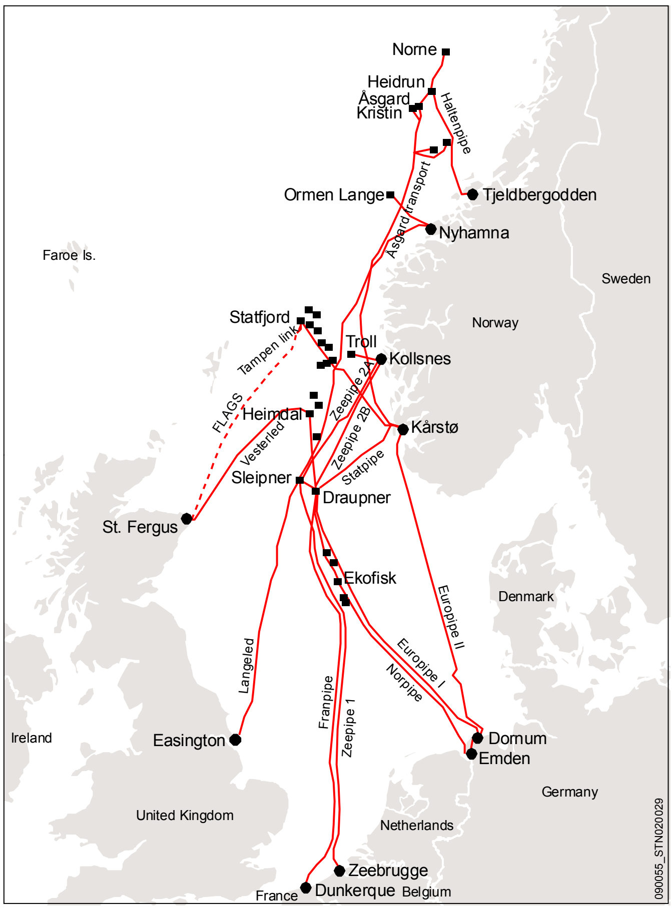
Diversion of LNG cargoes. In 2008 StatoilHydro diverted eight Snøhvit cargoes originally designated Cove Point in the US.

LNG

In 2007, the first vessel with a cargo of liquefied natural gas from the Snøhvit field left port at Melkøya. As well as pipeline-based supply, StatoilHydro now also supplies gas for export from the Norwegian continental shelf in a cooled state, as LNG, by ship. LNG gives us increased flexibility in terms of marketing gas globally. During 2008, LNG cargoes have been delivered to customers in Europe, the US and Japan. The plant at Melkøya is the first LNG production facility in Europe and it is a key component in StatoilHydro's focus on LNG, which is one of the fastest growing gas markets in the world. Snøhvit LNG is a pioneering and technologically innovative project. Since the scheduled shutdown during the summer 2008, Snøhvit has maintained a stable production at around 80% of the planned capacity. Our contractual delivery commitments to our customers Iberdrola and SNG commenced on 1 October 2006. To meet our obligations, we have put into effect mitigation activities, such as purchasing of replacement LNG and piped gas, to supplement available Snøhvit LNG.

3.3.4 Norway's gas transport system

The Norwegian gas pipeline system has been developed over the last 30 years to become an integrated gas pipeline system, connecting gas producing fields via processing plants on the Norwegian mainland to receiving terminals in Europe.



NCS infrastructure. An extensive pipeline system connects the NCS with the European market.

Norway's gas pipelines currently have a total length of 7800 kilometres. Since 2003, all gas pipelines with third party customers are unitized into a single joint venture, Gassled, with regulated third party access. The Gassled system is operated by the independent system operator, Gassco AS, a company wholly owned by the Norwegian State. In 2008, the Gassled system transported 94.6 bcm (3.3 tcf) of gas to Europe.

The Gassled system was expanded in 2006 with the Langeled pipeline from Nyhamna to Easington. The Tampen Link pipeline from the Statfjord platform to the British Flags pipeline system was included in 2007. In 2009 the Gassled system is further expanded through the merger of the Kvitebjørn gas pipeline, Norne Gas Transportation System and the Etanor ethane fractionation system at Kårstø. When new gas infrastructure facilities are merged into Gassled, the ownership shares are adjusted in relation to the relative value of the assets and each owner's relative interests.

From 1 January 2011, the Gassled ownership interests are planned to be adjusted due to an agreed increased ownership interest for Petoro. Similar adjustments of the ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA are expected to be made. In addition, StatoilHydro's future ownership interest in Gassled may change as a result of inclusion of new infrastructure, or if Gassled undertakes investments without participation from its owners in proportion with their ownership interests in Gassled.

StatoilHydro acts as technical service provider (TSP) for Gassco for the Kårstø and Kollsnes processing terminals as well as for the major part of the pipeline infrastructure system.

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

The tables below show facts of the NCS gas pipelines, including transportation routes and daily capacities, and our ownership in Gassled and other terminals.

Gas pipelines included in Gassled	Start-up date	Product	Start point	End point	Transport capacity [1] mmcm/day	StatoilHydro share in %
Zeepipe						
Zeepipe 1	1993	Dry gas	Sleipner riser platform	Zeebrugge	40.9	See Ownership structure Gassled
Zeepipe 2A	1996	Dry gas	Kollsnes	Sleipner riser platform	72.0	
Zeepipe 2B	1997	Dry gas	Kollsnes	Draupner E	71.0	
Europipe 1	1995	Dry gas	Draupner E	Dornum/Emden	44.5	
Franpipe	1998	Dry gas	Draupner E	Dunkerque	52.4	
Europipe II	1999	Dry gas	Kårstø	Dornum	64.6	
Norpipe AS	1977	Dry gas	Norpipe Y (Ekofisk Area)	Emden	43.1	
Åsgard Transport	2000	Rich gas	Åsgard	Kårstø	70.4	
Statpipe						
Zone 1	1985	Rich gas	Statfjord	Kårstø	26.8	
Zone 4A	1985	Dry gas	Heimdal	Draupner S	33.3	
			Kårstø	Draupner S	20.1	
Zone 4B	1985	Dry gas	Draupner S	Norpipe Y (Ekofisk Area)	30.0	
Oseberg Gas Transport	2000	Dry gas	Oseberg	Heimdal	39.9	
Vesterled (Frigg transport)	2001	Dry gas	Heimdal	St. Fergus	36.0	
Langeled North	2007	Dry gas	Nyhamna	Sleipner Riser	Approx. 70.0	
Langeled South	2006	Dry gas	Sleipner	Easington	68.0	
Tampen Link	2007	Rich gas	Statfjord	FLAGS	26.5 [2]	
Norne Gas Transportation System [3]	2001	Rich gas	Norne field	Åsgard Transport	11.0	
Kvitebjørn gas pipeline [4]	2004	Rich gas	Kvitebjørn	Kollsnes	25.4	

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

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

3) To be included in Gassled from 1 January 2009.

4) To be included in Gassled when operational after the pipeline repair in 2009.

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

Terminal facilities included in Gassled	Start-up date	Product	Location
Zeepipe JV			
Europipe receiving facilities	1995	Dry gas	Dornum, Germany
Europipe metering station	1995	Dry gas	Emden, Germany
Norsea Gas AS	1977	Dry gas	Gas Terminal, Emden, Germany
Statpipe JV (Kårstø gas treatment plant)	1985	Dry gas/NGL	Kårstø, Norway
Easington Receiving Facilities	2006	Dry gas	Easington, UK
Vesterled JV (Frigg terminal)	1978	Dry gas	St. Fergus, Scotland
Kollsnes Gas Plant	1996	Dry gas/NGL	Kollsnes, Øygarden Norway
Etanor DA [1)]	2000	Ethane	Kårstø, Norway

1) Etanor DA facilities was transferred to Gassled 1 January 2003 whilst the right to the tariff income will be transferred from the Etanor DA owners to Gassled as of 1 January 2009.

Terminals not included in Gassled	Start-up date	Product	Location
Zeepipe terminal JV [1)]	1993	Dry gas	Zeebrugge, Belgium
Dunkerque terminal DA [2)]	1998	Dry gas	Dunkerque, France

1) Gassled owners hold 49% interest in the terminal.

2) Gassled owners hold 65% interest in the terminal.

Ownership structure Gassled	Period 2007-2008 [(1)]	Period 2009-2010 [(2)]	Period 2011-2028
Petoro AS[(3)]	37.89%	38.46%	46.51%
StatoilHydro ASA	32.06%	32.10%	28.32%
ExxonMobil	9.66%	9.43%	8.03%
Total	8.00%	7.78%	6.04%
Shell	5.33%	5.32%	4.92%
Norsea Gas AS	2.81%	2.73%	2.25%
ConocoPhillips	2.02%	2.00%	1.67%
Eni	1.56%	1.53%	1.27%
Dong	0.68%	0.66%	1.00%
StatoilHydro interest including 28.58% of Norsea Gas AS	32.86%	32.88%	28.96%

(1) Change effective date 2007 is 1 September 2007.

(2) Change effective date 2009 is 1 January 2009. The changes are due to inclusion of the pipelines Norne Gas Transportation System, Kvitebjørn Gas Pipeline and the right to the Etanor tariff income respectively.

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

3.3.5 Kårstø gas processing plant

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

Kårstø. Kårstø is currently preparing for the future with the KEP2010

Kårstø processes rich gas and condensate, or light oil, from the NCS received via the Statfjord-Kårstø pipeline, the Åsgard-Kårstø pipeline and the Sleipner condensate pipeline. The treatment plant currently has a rich gas capacity of 88 mmcm per day. Products produced at Kårstø include ethane, propane, iso-butane, normal butane and naphtha and stabilized condensate. When all these elements have been separated from the gas, the remaining gas (dry gas) is sent to customers via the Statpipe, Europipe II and Rogass pipelines. The treatment plant has currently a dry gas export capacity of 78 mmcm per day.

In order to meet technical requirements and future needs, the Kårstø processing plant will undergo comprehensive upgrading over the next few years. KEP2010 is the project name for several projects intended to make Kårstø facilities more robust for safe and efficient operations. The project's framework investment is estimated at around NOK 6.5 billion. The first project was successfully completed in 2008. Plans call for the completion of the remaining KEP2010 projects between 2010 and 2012. Civil work started late 2008. The KEP2010 workforce working on site will comprise around 500 personnel at any given time. In 2008 Kårstø produced 24.6 bcm of dry gas, 0.8 million tonnes of ethane, 3.2 million tonnes of LPG and 2.2 million tonnes of condensate/naphtha exported to customers worldwide.

3.3.6 Kollsnes gas processing plant

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

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

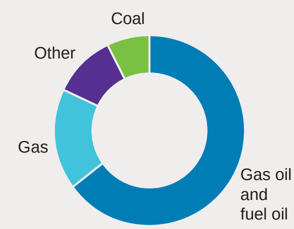
The plant was initially built to receive gas landed from the Troll field through two 36-inch pipelines. The plant currently has a design capacity of 147 mmcm per day. In 2008 an upgrade of the flash gas compressor and the condensate system was successfully completed to increase the robustness of the plant. In 2008, Kollsnes produced 33.8 bcm of dry gas and 82.8 mmcm of condensate.

3.3.7 Gas sales agreements

StatoilHydro is required by the Norwegian State to manage, transport and sell gas on behalf of the SDFI. StatoilHydro manages, transports and markets approximately 80% of all NCS gas.

Due to the relatively large size of NCS gas fields and the extensive cost of developing new fields and gas transportation pipelines, most of StatoilHydro's gas sales contracts are long-term contracts, which typically run for 10 to 20 years or more. Under these contracts the purchasers agree to take daily and annual quantities of gas and, if the gas is not taken, they are obliged to pay for the contracted quantity. The majority of StatoilHydro's long-term sales contracts have reached plateau level.

LONG TERM SALES INDEXATION SPLIT



Prices under traditional long-term contracts are generally tied to a formula based on the prevailing prices for substitute fuels to natural gas, typically heavy fuel oil and gas oil. By contrast, the most recent long-term gas sales contracts in the UK are priced with reference to a daily UK market gas price index. There can be significant price fluctuations during the life of the contract. Prices under the traditional long-term contracts are typically adjusted quarterly and are calculated on the basis of prices prevailing in the three to nine months before the date of adjustment as published in reference indices. However, the price formula, which allows for monthly or quarterly adjustment, does not pick up on all trends in the marketplace, e.g. changes in the taxation of gas and competing fuels imposed by national governments. Therefore, most of our long-term gas contracts contain contractual price adjustment mechanisms that can be triggered at regular intervals by either the buyer or the seller. Under our long-term sales contracts either party is entitled to initiate a price review process under certain circumstances as set forth in these contracts.

In 2008, StatoilHydro was involved in commercial discussions (in lieu of price review) or in formal price review processes for approximately 70% of the volumes covered by our long-term sales contracts.

3.4 Manufacturing and Marketing

3.4.1 Industry overview

As the current economic recession unfolds, we expect the change in the global demand for oil products to be negative in 2009 and maybe in 2010.

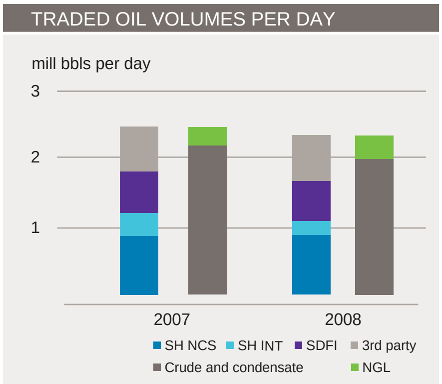
We expect the current economic downturn will revert to the long term trend of two-and-half to four percent growth. We expect demand to increase in parallel with a recovery in the global economy. Such growth will mainly be seen in emerging markets, as environmental policies and low population growth will constrain oil demand in mature economies.

In the medium to long term, we see growth limitations in global oil supply capacity. Oil production outside OPEC countries has already showed signs of flattening out, mainly due to the natural decline in output from mature oil fields. Supply growth will mainly come from OPEC countries in the future. In the longer term, we also expect limitations to OPEC production, due to lack of investment capacity and policies to make the period of stable oil revenues last as long as possible. In this context, we see incentives to develop both unconventional oil resources and alternative sources of oil products. There is a need to develop technologies to do this in a more environmentally acceptable way.

In the longer term, oil demand will therefore be limited by supply capacity. The supply side will also set limitations as to the requirements for refinery capacity. A number of refineries are currently under planning and construction around the world, and despite some delays due to the economic downturn, refinery capacity is expected to be more than sufficient in the years ahead. However, with higher prices and limited supply, we expect oil to continue its trend towards becoming primarily a fuel source for transport, such as gasoline, jet fuel and diesel, and less of a source for energy for stationary use, such as heating. This will put further pressure on refineries to increase the yield of these desired products. Income from refining will therefore mainly come from the upgrading of heavy oil components into transportation fuel products.

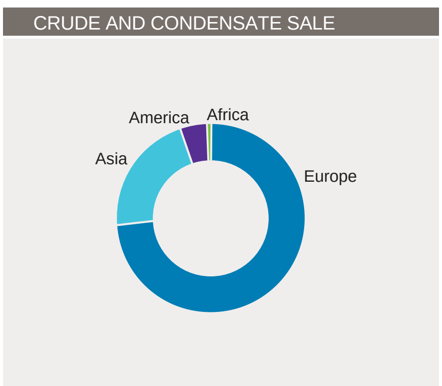
In developed economies, the legislative drive to remove sulphur and other pollutants from oil products is seen coming to an end now that the goals have been achieved, and future regulations are expected to focus on biofuel or other renewable content. However, an issue remains as to whether new regulation will seek to migrate shipping away from using heavy fuel oil to using diesel, in order to cut emissions. That could put increased pressure on a diesel market that already looks tight due to a lack of sufficient diesel upgrading capacity.

3.4.2 Oil Sales, Trading and Supply



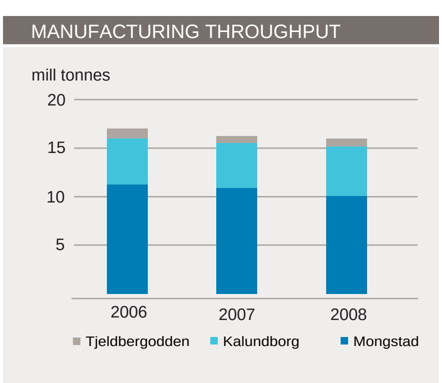
We are one of the largest net sellers of crude oil in the world, operating from sales offices in Stavanger, Oslo, London, Singapore and Stamford, selling and trading crude oil, condensate, NGL and refined products.

We market and sell our own volumes of crude and NGLs, together with those of the Norwegian State and third party volumes. In 2008, we sold 717 mmbbl of crude oil and condensate. This included sales to our own refineries and other internal entities. The main crude oil market for StatoilHydro is in north-western Europe. In addition, we also sell volumes to North America and Asia. Most of the crude oil volumes are sold in the crude spot market based on publicly quoted market prices. Of the total volumes sold in 2008, approximately 45% were StatoilHydro volumes.



3.4.3 Manufacturing

We are majority owner and operator of the Mongstad refinery and Tjeldbergodden methanol plant in Norway, sole owner and operator of the Kalundborg refinery in Denmark, and operate the Oseberg Transportation System including the Sture crude oil terminal.



We are majority owner (79%) and operator of the Mongstad refinery in Norway, which has a crude oil distillation capacity of 179 mbbl per day, and sole owner and operator of the Kalundborg refinery in Denmark, which has a crude oil and condensate distillation capacity of 118 mbbl per day. In addition, we have the rights to 10% of the production capacity at the Shell operated refinery in Pernis, The Netherlands, which has a crude oil distillation capacity of 400 mbbl per day. Our methanol operations consist of our 81.7% stake in the gas-based methanol plant at Tjeldbergodden, Norway, which has a design capacity of 0.95 million tonnes per year.

We also operate the Oseberg Transportation System (36.2% stake) including the Sture crude oil terminal. The plant was built to receive crude from the Oseberg field through a 28-inch pipeline, and since 2003 has also been receiving crude from the Grane field through a 29-inch pipeline. Oseberg blend (after stabilisation), Grane blend and LPG are exported, and condensate is piped to Mongstad.

The following table gives operating characteristics of the plants at Mongstad, Kalundborg and Tjeldbergodden.

	All data for year ended 31 December											
	Throughput [1]			Distillation capacity [2]			On stream factor % [3]			Utilization rate % [4]		
Refinery	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
Mongstad	**10.0**	10.9	11.2	**8.7**	8.7	8.7	**92.2**	97.8	99.1	**88.2**	93.2	97.9
Kalundborg	**5.2**	4.7	4.9	**5.5**	5.5	5.5	**88.3**	96.4	94.7	**90.3**	91.7	91.0
Tjeldbergodden	**0.91**	0.70	0.89	**0.95**	0.95	0.95	**98.9**	81.7	94.6	**96.5**	97.7	95.6

[1] Actual throughput of crude oils, condensates, NGL, feed and blendstock, measured in million tonnes. Higher than destillation capacity for Mongstad due to high volumes of fuel oil and NGL not going through the crude destillation unit.

[2] Nominal crude oil and condensate distillation capacity, and methanol production capacity , measured in million tonnes.

[3] Composite reliability factor for all processing units, excluding turnarounds.

[4] Composite utilization rate for all processing units, stream day utilization.

3.4.3.1 Mongstad

The Mongstad refinery is a medium-sized, modern and sophisticated refinery. It is linked to offshore fields, the Sture crude oil terminal and the Kollnes gas terminal, making it an attractive site for landing and processing hydrocarbons.

Mongstad.

The Mongstad refinery, built in 1975, significantly expanded and upgraded in the late 1980s and subject to considerable investments over the last 15 years to meet new product specifications, is a medium-sized, modern and sophisticated refinery. The refinery is directly linked to offshore fields through two crude oil pipelines and indirectly linked through an NGL/condensate pipeline to the crude oil terminal at Sture and the gas terminal at Kollsnes, making Mongstad an attractive site for landing and processing hydrocarbons and for further development of our oil and gas reserves. The main facilities at Mongstad, in addition to the refinery, are a crude oil terminal, owned 65% by StatoilHydro, and an NGL terminal, owned by Vestprosess, in which StatoilHydro has an ownership interest of 34%.

The refinery is owned 79% by StatoilHydro and 21% by Shell. We have a service agreement with Shell Global Solutions, a Shell subsidiary, which provides technical operational support, project development support and general technical advice to Mongstad.

Approximately 45% of Mongstad's total production is delivered to the Scandinavian markets and 55% is exported to north-western Europe and the United States.

The following table shows the approximate quantities of refined products (in thousand tonnes) produced at Mongstad for the periods indicated. As shown below, in addition to crude, the Mongstad refinery upgrades large volumes of fuel feedstock, NGL from Oseberg and Tune, and condensate from Troll, Kvitebjørn and Visund.

Mongstad product yields and feedstock	For the year ended 31 December 2008		2007		2006	
LPG	**311**	**3%**	373	4%	359	3%
Gasoline / naphtha	**3,902**	**39%**	4,721	43%	4,802	43%
Jet / kerosene	**820**	**8%**	755	7%	801	7%
Gasoil	**3,680**	**37%**	3,865	35%	4,050	36%
Fuel oil	**485**	**5%**	311	3%	302	3%
Coke / sulphur	**190**	**2%**	222	2%	231	2%
Fuel, flare & loss	**575**	**6%**	692	6%	620	6%
Total throughput	**9,963**	**100%**	10,939	100%	11,165	100%
North Sea crude oils:						
Troll, Heidrun (FOB crude oils)	**4,676**	**47%**	4,751	43%	5,508	49%
Other North Sea crude oils (CIF crude oil)	**3,072**	**31%**	3,780	35%	2,616	24%
Residue	**1,132**	**11%**	1,265	12%	1,323	12%
Other fuel and blendstock	**1,083**	**11%**	1,143	10%	1,718	15%
Total feedstock	**9,963**	**100%**	10,939	100%	11,165	100%

Note: Changes in throughput and yields are partly due to maintenance shutdowns (e.g. major turnaround in 2008).

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

The refinery reliability (i.e. on stream factor) was high in 2006 and 2007, but the site experienced some operational problems during 2008. In 2008 the largest turnaround in Mongstad's history was executed on schedule. There were no turnarounds in 2006 or 2007.

In 2006, we received final permission to build a combined heat and power plant (CHP plant) at Mongstad.

The CHP plant is part of a strategically important project for Manufacturing & Marketing. The use of heat from the CHP plant will result in significant improvements to the Mongstad refinery's energy efficiency. The CHP plant is expected to provide approximately 280 megawatts of electric power and 350 megawatts of process heat, however the utilisation will be lower for the first years after the unit is expected to come in commercial operation in 2010. The plant is under construction, and will be operated by Dong Energy, with StatoilHydro paying an annual fee for its use. By the end of 2008, the progress of the total CHP investment project was 80%. There is also an agreement with the Troll licensees, that this facility will supply power to the Troll A gas platform and the associated onshore Kollsnes processing plant. In addition to the CHP plant, the CHP investment project includes a new gas pipeline from Kollsnes and necessary modifications at the refinery.

StatoilHydro is involved in several projects together with the Norwegian government that aim to develop solutions for carbon capture and storage (CCS) at Mongstad. These projects are further described in report section 3.5.2.1 Operational review-Technology and New Energy-Research and development-R&D initiatives.

3.4.3.2 Kalundborg

The Kalundborg refinery is a small, yet highly efficient refinery. It has a high degree of flexibility, enabling it to produce a variety of products such as gasoline, jet fuel, diesel, propane and fuel oils to markets in Denmark and Sweden.

Kalundborg.

The refinery is connected through two pipelines (gasoline/gas oil) to our terminal at Hedehusene, near Copenhagen. Kalundborg's refined products are also supplied to markets in north-western Europe, mainly Germany and France. Fuel oil is exported to Italy and the US.

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

	For the year ended 31 December					
Kalundborg product yields and feedstock	**2008**		**2007**		**2006**	
LPG	**54**	**1%**	78	2%	96	2%
Gasoline / naphtha	**1,598**	**31%**	1,497	32%	1,545	31%
Jet / kerosene	**251**	**5%**	209	4%	259	5%
Gasoil	**2,105**	**40%**	1,997	42%	2,042	42%
Fuel oil [2]	**1,023**	**20%**	746	16%	775	16%
Coke / sulphur	**6**	**0%**	5	0%	5	0%
Fuel, flare & loss	**183**	**3%**	185	4%	193	4%
Total throughput [1]	**5,220**	**100%**	4,717	100%	4,915	100%
North Sea crude oils:						
Condensates: Ormen Lange, Snøhvit, Sleipner	**659**	**12%**	170	4%	1,088	22%
Other North Sea crude oils	**4,314**	**83%**	4,395	93%	3,641	74%
Other fuel and blendstocks	**247**	**5%**	153	3%	187	4%
Total feedstocks	**5,220**	**100%**	4,718	100%	4,916	100%

1) Total throughput has increased from 2007, The increase is explained by optimisation arising after startup of the Fuel Reduction plant, strong operational focus on throughput optimisation and no large turnaround in 2008

2) Fuel Oil volume has increased due to large import of flux material since the start of the Fuel Reduction Project

There was a turnaround in 2007.

Kalundborg is a plant with high energy efficiency and high utilisation. The refinery has improved its performance significantly in recent years through several small investment projects aimed at increasing flexibility, and improving yield/product quality. It produces high quality products, including low-sulphur petrol, in accordance with EU specifications.

The Fuel Reduction Project, which reduces production of heavy fuel oil and increases the production of sulphur-free auto diesel, was started up in 2008.

3.4.3.3 Tjeldbergodden

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

Tjeldbergodden.

We own 81.7% of the plant, which has a maximum proven capacity of 0.92 mmtpa. The actual throughput in 2008 was 0.91 mmtpa.

We also own 50.9% of Tjeldbergodden Luftgassfabrikk DA, one of the largest air separation units (ASU) in Scandinavia, which also owns the first Norwegian natural gas liquefaction plant, located at Tjeldbergodden with an annual gas (methane) capacity of 36 mmcm (1.3 bcf). Our partners are AGA (37.8%) and ConocoPhillips (11.3%). The ASU supplies oxygen to the methanol plant and AGA markets and sells the industrial gases produced.

3.4.3.4 Sture

The Sture terminal receives crude oil through two pipelines from the Oseberg area and the Grane field in the North Sea. The terminal is part of Oseberg Transportation System in which StatoilHydro has a 36.2% stake.

Sture terminal.

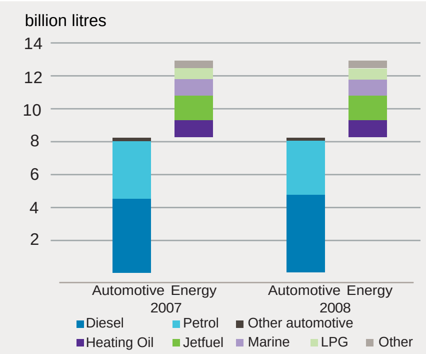
The terminal has a storage capacity for 6.3 million barrels of crude.

The processing facilities at Sture recover the lightest components from the unstable crude, extracting LPG mix (propane and butane) and naphtha. Two crude qualities and LPG mix are exported, and volatile organic compounds (VOC) are recovered when loading tankers. LPG and naphtha are also transported through the Vestprosess pipeline to Mongstad.

3.4.4 Energy and Retail

Energy and Retail has approximately 11,000 employees, and consists of approximately 2,100 service stations and 350 truck stops in eight countries. We also market refined products directly to consumer and industrial markets.

ENERGY AND RETAIL

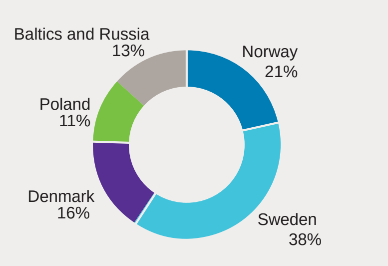


The full-service stations in the Retail segment provide automotive fuels, car accessories and basic vehicle service products. In addition, most stations offer consumer goods, including fast food, convenience products and basic groceries. In 2008, these stations, together with automated stations, sold approximately 8.4 billion litres of petrol and diesel. Sales from truck stops accounted for additional sales of 1 billion litres.

The following table lists these retail outlets by region or country as of 31 December 2008 and our volume of automotive fuel sales for the year ended 31 December 2008.

Retail outlets/country Service Stations	Scandinavia	Poland	Baltics	Russia	Total
StatoilHydro owned and operated	276	185	164	15	**640**
StatoilHydro owned and dealer operated	517	0	1	0	**518**
Dealer owned and StatoilHydro operated	0	0	0	0	**0**
Dealer owned and operated	254	44	10	0	**308**
Automated stations	555	41	17	0	**613**
Total	**1,602**	**270**	**192**	**15**	**2,079**
Truck Stops	**346**	**1**	**0**	**0**	**347**
Automotive fuel volumes (millions of litres)					
Petrol	2,453	361	521	37	**3,372**
Diesel	3,819	392	560	4	**4,775**
LPG/Ethanol	337	144	29	0	**510**
Total	**6,609**	**897**	**1,110**	**41**	**8,657**

ENERGY AND RETAIL *



*Retail fuel sales by region

In addition to the retail operations, Energy and Retail also supplies aviation and marine fuels, as well as a large number of Statoil-brand refined products. Such products include oil based heating fuels and lubricants, which are supplied to both retail and industrial customers. We have operations for lubricants and LPG in Poland and the Baltic countries, supplementing our strong market position in Scandinavia.

The majority of Energy and Retail sales are generated in Scandinavia. We have an approximate transport fuel market share of 36% in Norway and 23% in Denmark. In Sweden our transport fuel market share is approximately 33%, based on sales from Statoil and Hydro branded stations together with truck site sales and bulk deliveries. Other service stations are located in Poland, Russia and the Baltic countries; Estonia, Lithuania and Latvia. We rank as a market leader, measured in terms of fuel volumes sold, in Estonia and Latvia with approximately 26% and 34%, respectively, of the local transport fuel market in 2008.

Acquisition of Jet

On 21 October 2008, the European Commission granted permission for StatoilHydro to take over the bulk of the Jet self-service retail chain in Scandinavia that was then owned and operated by ConocoPhillips. To comply with the terms set by the commission, StatoilHydro agreed to sell 80 of the 274 filling stations acquired, so as to limit market concentration. StatoilHydro will also be obliged to sell 118 Hydro stations in Sweden as part of the divestment package.

The transaction is an important element in our endeavours to become the leading fuel company in Scandinavia.

3.5 Technology and New Energy

3.5.1 Industry overview

The success of our business is closely related to the application of the advanced technological expertise that for the most part has been acquired through our exploration and production activities on the NCS.

Many major challenges have been addressed, including operating in the harsh weather and environmentally sensitive conditions of the Norwegian Sea, transporting oil and gas across the deep Norwegian trench, and draining complex petroleum reservoirs characterised by high pressures and high temperatures. Much of this experience is increasingly being applied to StatoilHydro's international operations.

The renewable energy industry continues to grow, driven by ambitions to increase the contribution of sustainable energy to the total energy supply. Despite the challenges associated with the current financial crisis we believe that the new energy industry has gathered sufficient momentum in recent years for it to continue to be an important focus area for StatoilHydro. Although energy production from renewables is still modest in most countries, wind power, solar energy and biofuels are developing into significant industries.

3.5.2 Research and development

3.5.2.1 R&D initiatives

The Research and Development (R&D) business cluster concentrates on StatoilHydro's technology focus areas in which the company wishes to develop and sustain distinctive technology positions.

The R&D portfolio is structured in six programmes: Exploration, IOR - Reservoir Drilling & Well, New Development Solutions, Oil and Gas Value Chain, New Energy/New Ideas and Academia.

Research and Development expenditures were NOK 2.24, NOK 1.97 and NOK 1.62 billion in 2008, 2007 and 2006, respectively. R&D expenditures are partly financed by joint venture partners of StatoilHydro operated activities. Cooperation with external partners, for example academia, R&D institutes and suppliers are key to technology provision. Typically more than 50% of the R&D expenditure is external work.

As conventional fossil fuels become ever harder to find, our company is increasingly setting its sights on remote geographical areas and developing unconventional hydrocarbon sources such as tight gas, oil sands and building growth platforms in carbon-neutral energy sources (renewables).

In exploration technology, we are developing new basin and prospect concepts that enable better global screening, exploration drilling and quantitative prediction of basin prospectivity. In addition, we are working on identification, characterisation, and prediction of deep-water plays for exploration within complex geological settings. Incorporation of integrated geophysical and geological methodologies into next generation workflows results in continued improvement of subsurface imaging and interpretation. The goal is to considerably reduce the risk of drilling dry holes and enable us to determine the presence of commercially viable reservoirs prior to drilling.

For proven reservoirs, the aim is to optimise hydrocarbon recovery by improving ways of identifying remaining reserves and draining our reservoirs as efficiently and effectively as possible. Important success factors here are data integration and faster model updates for integrated operations across disciplines, organisational entities and geographical areas. The objective is to achieve more reliable, better and swifter decisions. We develop fit-for-purpose modelling techniques for better and more efficient modelling of reservoir drainage, more efficient drilling and intervention solutions, and more cost effective well construction methods.

Innovative offshore field development solutions lead to a transition from topside to intelligent, remotely-operated, autonomous seabed facilities, coupled with ultra-long, subsea tie-backs and wellstream compression devices. However, we also see that compact processing technology developed for subsea applications has a substantial potential to improve efficient production on existing platforms. The aim is to improve regularity and performance for both new and producing fields. Furthermore, it is necessary to increase the knowledge about design and operation in ice-bound areas and in ultra-deepwater conditions. We have also started to develop technology for processing and transportation of offshore heavy oil.

The opportunities in gas value chain technology may lie in gaining greater access to, and cost-effectively developing, difficult unconventional gas resources. We are developing technology for processing and transportation of challenging gas as well as pipeline solutions for deep and ultra-deep assets. In supporting our M&M business we work on refining technology for handling challenging and unconventional crude oil.

The Calgary Heavy Oil Technology Centre was established early this year to strengthen our efforts in heavy oil technologies. The focus is on developing onshore extra heavy oil value chains and on improving recovery methods, water management and carbon capture.

The final demonstration of GTL technology on a semi-commercial scale was completed this year. This concludes a demonstration programme where a Joint Venture consisting of StatoilHydro together with partners Lurgi and PetroSA has demonstrated the technology.

Our commitment to environmental stewardship is twofold: meeting our objective of zero harm to the environment by expanding our toolkit of environmental monitoring and integrated risk-modelling systems, and secondly, by creating business in new energy sources. In addition to our present activities in offshore wind and biofuels, we plan to further investigate opportunities in renewable energy sources and carriers. We are working on cost and energy efficient carbon capture and storage (CCS) with no harm to the environment, and we believe technological innovation is the key to meeting a profitable, sustainable, low-carbon energy future. Integrating trend-breaking technologies such as biotechnology and other new ideas into the value chains is also part of our research and development effort.

As part of the research effort we are pursuing an extensive collaboration programme with academia in which we gain access to world class research within strategic areas for StatoilHydro. By stimulating the development of leading competence within the energy segment we also secure long term recruitment to science and technology.

By supporting collaboration between universities, research institutions and industry, we believe this also contributes to building a strong Norwegian petroleum cluster.

3.5.3 New energy

The New Energy portfolio has a particular focus on creating profitable business in the short and medium term through the Wind and BioFuels businesses.

Renewable Power Production
Today's wind portfolio consists of several onshore development projects in Norway and we are in the early phases of possibly developing the 315 MW Sheringham Shoal offshore shallow water wind project in the UK.

In May 2008 StatoilHydro approved the building of the Hywind pilot and this demonstration project will be the world's first full scale floating windmill. It is a 2.3 MW unit and is scheduled for operation off the west coast of Norway second half of 2009. Complementary offshore wind technologies are available through our equity positions in the Norwegian companies Sway AS and ChapDrive AS.

In 2008 we invested in Brightsource Energy, which develops technology for concentrated solar thermal power, and the Iceland Deep Drilling Project (IDDP), which is a joint-research programme within deep geothermal energy in Iceland.

Our existing technology investments have also begun to show promise. Pelamis, a wave energy device in which StatoilHydro has invested, was the technology chosen for the world's first wave energy park situated off the Portuguese coast. In addition, it has been selected for other new projects in the UK. Hammerfest Strøm AS, a tidal power technology company in which StatoilHydro participates together with Iberdrola/Scottish Power, has been selected to be used in projects planned by Scottish Power.

Sustainable Fuels
Today we own 42.5% of Mestilla, a 100,000 t/year rape seed biodiesel production facility in Lithuania, where production started in November 2007. Our strategy is to deliver rapid commercial growth within sustainable biofuels and to position ourselves for low cost next generation biofuel production. StatoilHydro's ambition is to become a significant provider of sustainable biofuels with a global production and trading position and to be a high quality supplier in our retail markets.

Being able to produce biofuels sustainably is a prerequisite for developing our biofuels business. We are working actively to prevent damage to biodiversity, ecosystems and areas of high conservation value and emphasise the greenhouse gas accounts in a life cycle perspective. Our aim is to contribute to positive local development through competence building and job creation.

Our activities within hydrogen are centred on both short and long-term options. Through our subsidiary Hydrogen Technologies we are actively developing and promoting ongoing sales of water electrolysis technology. We have also developed hydrogen station technologies aiming at the emerging markets within the transport sector.

StatoilHydro opened Norway's first hydrogen filling station in Stavanger in August 2006 and the second in Porsgrunn in June 2007. The stations are part of the national development project HyNor, in which StatoilHydro is a leading player. HyNor is a unique Norwegian joint industry initiative to demonstrate real life implementation of hydrogen energy infrastructure along a route of 580 kilometres from Oslo to Stavanger.

On Utsira, an island off the west of Karmøy, StatoilHydro owns and operates a hydrogen demonstration plant where electricity from wind turbines is used to provide power to the local society and to produce hydrogen. When wind speeds are not sufficient to provide enough electricity, the hydrogen plant is used to generate power.

CO_2 Management

Carbon capture and storage (CCS) is regarded as one of the main means to combat climate change. StatoilHydro has long been a pioneer of CCS within oil and gas production and currently operates some of the world's largest projects in this area.

- When StatoilHydro started to capture and store CO_2 at Sleipner in October 1996, it was the first of its kind in the world. Its implementation has meant a reduction in CO_2 emissions of nearly one million tonnes per year, equivalent to the emissions from 400,000 cars.
- The Snøhvit field in the Barents Sea now provides gas to Europe's first LNG (liquefied natural gas) production site. The Hammerfest LNG-plant at Melkøya will capture about 0.7 million tonnes of CO_2 per year from the well stream when in full production. The CO_2 will then be compressed and sent back to the offshore field for storage in a reservoir 2500 metres below the seabed.
- StatoilHydro is a co-operator with BP in the In Salah field located in the middle of the Sahara Desert in Algeria. Since 2004, up to 1.2 million tonnes of CO_2 have been captured and stored in the In Salah field per year.

By using this experience as a base and placing the main focus on storage, StatoilHydro intends to generate new business from CO_2 management. The planned facilities at Mongstad will provide valuable experience in the transportation and storage of CO_2.

Our business efforts within CO_2 also include the development of the Clean Development Mechanism (CDM) projects under the UN. This activity builds on our CO_2 reduction experience within the oil and gas sector. Our main target regions are Mexico, China, and Indonesia. Country selection is based on CDM market conditions, StatoilHydro's presence in that country and other criteria such as emission data and sector attractiveness.

Technology commercialisation

Our Industry Development unit supports suppliers, innovators and entrepreneurs with their technology developments and commercialisation activities, thus helping to create robust suppliers and new technology products vital for our oil, gas and new energy activities. The unit also supports industries and technology development in other countries where StatoilHydro has operations.

Industrial Development acts as a catalyst by linking those developing new technology products to commercial activities and end users within StatoilHydro, providing funding and expertise, and taking strategic ownership in promising companies within the energy technology industry. Furthermore, StatoilHydro has ownership and engagement in all the major Science Parks and Incubators in Norway.

StatoilHydro actively benefits from venture activities to access new technologies. In the autumn of 2008 it was decided to strengthen this activity by establishing a special purpose company, Energy Capital Management AS, to manage corporate venture activities within StatoilHydro. This move represents a further focus on venture capital as a tool to accessing new technologies, and will support StatoilHydro's technology strategy and help capitalise on today's ownership positions within the venture business.

3.5.4 Technology development

StatoilHydro is the world's largest operator of offshore fields in water depths greater than 100 metres, and we have considerable experience in overcoming the challenges presented by harsh environments.

Nevertheless, there is a need to rapidly utilise new technology to increase the resource base and maximise production.

Technology & New Energy (TNE) is the centre of force for the development and implementation of new technology in the company. This is achieved by providing best practice support and expertise for our operations, developing world-class technical concepts for our development projects, and leading established corporate initiatives in order to improve our performance in exploration, IOR and integrated operations. In this manner, TNE will support the other business areas in achieving corporate targets for production growth, increased regularity, reduced costs and improved drilling efficiency.

Selected advances made in 2008 are summarised below:
One of the major challenges in exploration is to acquire the best seismic image of the subsurface, even in areas with very complex geology, and subsequently combine seismic data without compromising geological insights. Our ***Integrated Imaging workflow*** allows for improved integration of geology and geophysics in exploration subsurface imaging, leading to better subsurface interpretation in exploration and increases the probability of oil and gas discoveries. This method is a clear leader in exploration seismic imaging and interpretation and supports the company's quest to be the leading exploration company.

The first set of ***3D*** electromagnetic data (EM) was retrieved from the Troll area on the Norwegian Continental Shelf this year. Increased insight into acquisition and interpretation technology of the Troll data increases the use of EM in the exploration workflow and adds significantly to the use of EM data for subsurface identification of oil and gas. Electromagnetic data has potentially siginificant applications in hydrocarbon exploration by enabling the oil and gas to be detected in reservoirs instead of water. Combined with seismic data, the EM data can reduce uncertainty in exploration and lead to higher discovery rates.

The massive volume of exploration data and need for efficient analysis to ensure exploration success has led to the development of a proprietary version of Google Earth. The ***StatoilHydro Earth Exploration Toolbox,*** visualized in the Google Earth environment, is a significant step towards quick access and interpretation of exploration data, leading to an effective workflow for evaluating subsurface prospectivity. Such workflows assist the rapid development of subsurface geology models and increase the probability of locating prospective areas and layers for discovery of oil and gas.

StatoilHydro is now qualifying a new down-hole drilling tool, the ***Rotary Steerable System*** (RSS), together with Schlumberger. These tools will be used to drill sidetracks from old wells without removing the production tubing. A window out to the formation is made in one side of the old well and the RSS tool is then used to drill a new hole outside the window. This quick departure from the old well will dramatically increase the ability to reach reservoirs that could not be as efficiently reached before, if at all. The impressive steering characteristics of the tool also make it possible to reach targets further away from the old well and ultimately double the number of targets and recoverable reserves that can be reached with the use of this technology.

Current technology for capturing CO_2 from flue gases is associated with significant energy requirements and large capital costs. ***Exhaust gas recirculation*** (EGR) is a method known to reduce costs and energy requirements, and StatoilHydro has monitored the technology for several years. A technology qualification programme is under development for EGR in connection with the General Electric Frame 9E gas turbines at Mongstad.

3.6 Projects

3.6.1 Industry overview

On the NCS, the trend is away from a portfolio of major development projects and towards subsea tie-in projects and complex redevelopment projects on existing installations where vital work must be timed to coincide with planned turnarounds.

The growing portfolio makes the shortage of engineering competence just as critical as in previous years, with respect to the number of available engineering personnel and the competence and quality of work delivered. In addition, increased international activity is expected to challenge our ability to utilise our competence and allocate our resources in the most efficient way. As a result, there is a risk that engineering may be negatively affected, which in turn, may influence construction and completion progress.

High activity levels on the NCS will make strong demands on our ability to execute projects as sanctioned and in accordance with our HSE target of zero harm. To succeed, we must challenge established models, ensure continuous improvement and establish best practice on the basis of experience.

As regards physical deliveries of goods and services, we have only seen moderate price decreases while the oil price plunged during the second half of 2008. This remains a concern, and it means that our long term investment plans are being revised. However, we anticipate a high activity level in 2009.

3.6.2 Projects development

There is considerable diversity in our projects portfolio, ranging from new projects and improvements to existing assets to generate production growth on the NCS, to supporting the company's ambitions to become a global energy player.

On the NCS, projects such as Gjøa, Tyrihans, Morvin and Alve will contribute to continued production growth. Ormen Lange Offshore and Statfjord Late Life are examples of complex projects that are expected to contribute to optimising production from existing assets.

The following table gives a project overview

Project completions 2009 - 2010	Type
Offshore NCS	Alve, Gjøa, Norne M, Ormen Lange Offshore, Troll 02 Template, Tyrihans, Vega
Modifications NCS	Brage Prod. Water Re-injection, Heimdal New Power Generator, Kvitebjørn Gas Capacity Upgrade, Oseberg D HRSG, Oseberg F Low Pressure Prod., Sleipner A 10 bar inlet pressure, Snorre A Re-development IOR, Snøhvit Improvement Project, Statfjord Late Life, Troll A Compressors, Troll A Living Quarter Extension, Troll C Low Pressure Production, Veslefrikk Produced Water
Onshore	Mongstad Combined Heat and Power Plant, NOX Mongstad, Statoil Mongstad Miljøinvestering (SMIL)
New Energy	Hywind
International	In Salah Gas Compression, Leismer Demonstration, South Pars 6 - 8, Peregrino

Another dimension of complexity to our business comes from executing projects internationally -- an essential part of fulfilling the group's ambitions to become a truly global energy player. Examples of PRO's contributions in this respect are the Leismer, In Salah and Peregrino projects.

To build an international reputation as a world-class implementer of projects, the way in which we deliver results is as important the results themselves. That means delivering on time and cost, and without compromising high HSE and ethical standards.

3.6.2.1 Norwegian Continental Shelf

We continue to strengthen our solid position on the NCS with several large and complex new development projects currently being executed.

The largest project in our portfolio today is **Gjøa**, located west of the Sogn area. Gjøa is being developed with a semi-submersible production platform and five subsea templates The producing facility is designed in a way that makes it possible to process oil and gas from other smaller discoveries in the area in the future, such as **Vega** - a gas and condensate field that is being tied back to the platform in a joint pipeline.

The Gjøa platform will be provided with land-based electricity from Mongstad that is estimated to avoid emissions of 240,000 tonnes of carbon dioxide per year, equivalent to the annual emissions from 100,000 cars. At production start-up, expected to be in the autumn of 2010, we will hand over the operatorship of Gjøa to Gaz de France .

Tyrihans is a stand-alone subsea field development tied back to the Kristin platform. The field will be developed with four production/gas injection templates and one water injection template, with a total of 12 wells (eight oil producers, two gas injectors, one gas producer and one water injector).

The Tyrihans field was discovered in 1982/1983 and the PDO was approved by the Norwegian authorities in February 2006.

The remaining work prior to the estimated start-up in mid-2009 consists of topside modifications on Kristin and Åsgard B and delivery of the subsea production system and seawater injection system.

Another ongoing project located on the Halten Bank is **Morvin**. Initially it was not regarded as commercially viable when it was discovered in 2001. However, an appraisal well in the summer 2006 verified sufficient recoverable reserves, and Morvin was subject to an accelerated development process. PDO was issued to the authorities on 1 February 2008, and approved 28 April 2008.

Morvin is a High Pressure High Temperature field, and is being developed with technology solutions copied from Kristin. The two templates, with a total of four production wells, are tied in to Åsgard B, 20 kilometres away. Templates and production pipeline were installed during summer 2008 and topside installation work has commenced. Production start-up is scheduled for late 2010.

The **Yttergryta** subsea gas and condensate field development is an example of a relatively small but unique project in our portfolio. The discovery was made in the summer of 2007, and production start-up took place on 5 Januar 2009, four months ahead of schedule. The wellstream is tied back to the Åsgard B platform for processing and further export.

Ormen Lange Offshore is the second phase of the gigantic Ormen Lange gas field development. We currently have two separate ongoing projects on Ormen Lange; Southern Field Development and Subsea Compression Pilot. The purpose of these projects is to ensure optimal depletion from the field when the pressure in the reservoir drops. Groundbreaking work is now being done to qualify technology for subsea compression on Ormen Lange, and, if successful, the new technology could contribute to considerable cost savings, not only for the Ormen Lange partners, but for the entire oil and gas industry.

The field was developed with seabed installations at depths down to 1100 metres, combined with an onshore plant at Nyhamna in Aukra municipality in Norway for processing and exporting the gas. The gas is exported through the world's longest subsea pipeline, Langeled, 1200 kilometres to Easington on the east coast of Britain. The gas can also be transported via the riser platform on the Sleipner field in the North Sea to customers on the European continent.

Following a gradual increase in production over the first two to three years, the field is expected to produce 70 million standard cubic metres of gas per day.

3.6.2.2 Onshore facilities

Large redevelopment programmes are currently underway at the Kårstø, Mongstad and Kollsnes production sites.

A total of approximately NOK 14 billion is currently being invested to ensure regularity of gas production, to prepare for future volumes, and to ensure that future HSE requirements from authorities are met by sanctioned projects offshore.

At Mongstad, the projects related to the construction of a **Combined Heat and Power** (CHP) plant are well underway. StatoilHydro is executing a major refinery upgrade and building a gas pipeline from Kollsnes to Mongstad in relation to this CHP plant. The latter has been completed by mid December 2008. In parallel, StatoilHydro is executing a large environmental project, called **SMIL**, which also is planned to be completed during 2009. The CHP plant is built and operated by DONG Energy and is planned to start up early in 2010.

At Kårstø, several smaller projects have been gathered together in the **Kårstø Expansion Project 2010** (KEP 2010). The first part is a compressor upgrade which will make it possible to increase the pressure, and thus enable more stability in the gas flow through the export pipelines leaving Kårstø. This sub-project was completed in fourth quarter of 2008.

The second part of the project is a complete modernisation and upgrading of the security and control systems at the site, to prepare the plant for several more years of production and to meet stricter future HSE standards. A project replacing the NGL Metering stations was sanctioned late in 2008. The NGL Metering stations are planned to be started up by the end of 2011.

The **Kollsnes Flash Gas and Condensate** project is an upgrade of the existing system due to capacity and regularity limitations. The installation of a new flash gas compressor train and a new condensate treatment train was completed by the end of December 2008 and will contribute to increasing production and operating regularity at the Kollsnes processing plant. In addition, capacity for future production of 40 million standard cubic metres per day is built into the system.

3.6.2.3 International

We have a number of key projects taking place internationally, in such countries as Algeria, Canada, Brazil and the US.

In Algeria we are involved in onshore gas production and exploration activities. The **In Salah Gas Compression** project is part of the original development plan for In Salah, and it consists of turbine and electricity-driven gas compressor facilities that will be installed at Reg, Teg and Kretchba, respectively. The purpose of the new compressor facilities is to counteract the declining production rates from the three fields. Construction work has started with site preparations, prefabrication of pipes and equipment delivery. The project is behind schedule, but mitigating actions have been implemented to secure the schedule and prevent further delays.

The **Leismer** field is located in our oil sands lease in the Athabasca region in Alberta, Canada. The Leismer Demonstration project is the first oil sands development being undertaken by StatoilHydro, and is based on Steam Assisted Gravity Drainage (SAGD) technology to extract bitumen from the reservoir. The Central Processing Unit will have a processing capacity of 20 mboe per day. Four well pads have been constructed with a total of 22 well pair slots for steam injection and bitumen extraction. A 12 inch bitumen transport pipeline with a total capacity of 40 mboe per day and an eight inch diluents pipeline from site to Cheecham (length 71 kilometres) is also planned to be constructed. Civil engineering work on the processing site has been completed and installation of prefabricated modules for the processing unit is ongoing. Start-up of bitumen production is scheduled for late 2010.

On 4 March 2008, StatoilHydro signed an agreement with Anadarko to purchase Anadarko's remaining 50% share of the **Peregrino** field in Brazil. The agreement also involves transfer of the operatorship to StatoilHydro, and we now hold a 100% ownership share in the field. The transfer of project responsibility took effect on 2 June 2008, and was formally approved by the Brazilian petroleum authorities, Agencia National de Petróleo, on 11 December 2008.

The Peregrino field is located 85 kilometres off the Brazilian coast in approximately 100 metres of water. A development plan for Phase 1 was approved early 2007, containing two drilling and wellhead platforms and a floating vessel for production, storage and offloading of oil (FPSO). The first oil is planned to come on stream in 2011 and plateau production of 100 mboe per day is expected to be reached within the first year of production.

The project is progressing according to schedule, and the two wellhead platforms are currently under construction at Kiewit's yard in Corpus Christi, Texas. The FPSO vessel, *Mærsk Nova*, is being upgraded at the Keppel Tuas yard in Singapore, while the process facility is being fabricated at the Keppel yard in Batam.

On 12 December 2002, we became operator of the development of the offshore part of the **South Pars phases six-seven-eight** project in Iran. The South Pars offshore project phases six, seven and eight consist of three wellhead platforms with three pipelines for gas to shore, a condensate loading line and associated single point mooring (SPM) for condensate exports, the drilling of 27 production wells, the hook-up of three pre-drilled wells and required reservoir management.

Gas production from South Pars phase eight started in August 2008 and from phase 6 in December 2008. Production from the third and final phase, South Pars phase seven, is expected to commence after the summer of 2009. Installation of the third and final rich gas export pipeline began in December 2008.

3.6.2.4 Redevelopments

A major part of our project portfolio consists of activities relating to ongoing redevelopment efforts, aimed at maximising production from the NCS.

As fields mature, production equipment needs upgrading. In the years ahead, a number of fields will need upgrading or renewal of drilling units, control systems, cranes and other major redevelopment efforts.

We endeavour to organise these tasks as field projects in line with coordinated master plans for the different fields, such as the various redevelopment projects taking place at Statfjord, Troll and Oseberg, among others.

The PDO for the **Troll** projects was submitted to the Ministry of Petroleum and Energy this summer. The Troll B Gas Injection project and the P12 pipeline to Kollsnes are both part of the PDO. The extension of the living quarters on Troll A and low-pressure production on Troll C are also vital projects in the Troll field.

The various redevelopment projects related to the **Oseberg** field represent a substantial investment aimed at ensuring the vitality of the field in the coming years. Vital projects include low-pressure production on Oseberg F, a heat recovery steam generator on Oseberg D, upgrading of the drilling unit at Oseberg B and upgrading of the Oseberg C Mud module.

Over the next few years, the **Statfjord Late Life** project will redevelop all three Statfjord installations from oil processing to gas processing facilities, thereby extending the lifetime of the field by several years. We expect the daily production of gas to exceed daily oil production on Statfjord in 2010.

3.7 People and the group

The impact of the global economic turmoil on our employees and the labour market within our industry is not yet fully evident. We are planning for growth and need to maintain and further develop our core competencies.

Our overall strategic objective in 2008 has been to build a company culture that is based on our values and driven by performance. In everyday work life, this means that we create a positive working environment that makes our people attracted to, inspired by and committed to our company.

3.7.1 Our people

Our rapid international growth challenges our ability to maintain recruitment of highly skilled personnel from all countries in which we operate.

StatoilHydro employs approximately 29,500 people worldwide. Our people are central to the delivery of the StatoilHydro business strategy and sustainable development policy. In 2008 we continued to advance our people strategy, which focuses mainly on integrating post-merger best practices, maintaining cooperation with our unions, recruiting, developing skills and improving employee performance.

At 31 December 2008 and 31 December 2007, we had 29,500 employees worldwide. The table below provides the number of employees at year-end for each of the past 3 years and a breakdown of employees by geographic location.

		As of 31 December	
Number of employees	**2008**	**2007**	**2006**
Norway	**18,001**	18,102	13,987
Europe	**10,460**	10,095	11,015
Africa	**145**	101	49
Asia	**338**	206	203
South America	**103**	71	59
North America	**449**	317	95
IS Partner *		611	
Total	**29,496**	29,503	25,408

* IS Partner is an information systems service provider that was sold to an external party in February 2008. The employees are primarily situated in Norway.

The increase in employees by approximately 4100 or 16% from 2006 to 2007 can be primarily attributed to the merger between Statoil ASA and Hydro oil and energy activities.

Cooperation with Unions. Our cooperation with the unions has been improved, by redefining the agreement between the parties in ICEM. Our process for people performance, development and deployment has been simplified and improved.

Recruiting. The percentage of non-Norwegians working at our various locations in Norway has increased from 5.12% in December 2007 to 5.88% in December 2008. At the end of 2008, 11,400, or 39% of our people were employed outside Norway.

StatoilHydro is a knowledge and technology-based company and our people are highly qualified to do their work: 56% of the employees in StatoilHydro ASA have a university or college background, and having 27% have a craft certificate. StatoilHydro employs the most apprentices in Norway, with 176 apprentices joined our company in 2008. The total number of apprentices in StatoilHydro at December 2008 was 337.

At the end of December the average age of our employees at StatoilHydro ASA was 44 and the majority of our people, 69%, were between 35 and 55 years old, while 19.5% of our people were less than 35 years old. In 2008, the overall turnover at StatoilHydro ASA was 1.9%. The turnover percentage for women was 1.5%, and for men 2.1%.

3.7.2 Diversity and equality

We promote diversity of gender, age and ethnicity among our employees.

The importance of diversity is stated in our values and in our ethical codes of conduct. We aim to create the ame opportunities for all of our employees, regardless of gender, age on ethnicityand do not tolerate discrimination or harassment of any kind in our workplace.

By December 2008, 37% of our people were women, and 40% of the members on our board of directors were women. The proportion of female managers is 27%, and among managers under the age of 45, the proportion is 35%. Moreover, women are relatively well represented in the technical disciplines. In 2008, 25% of our staff engineers were women, and among staff engineers with up to 20 years' experience, the proportion of women is 28%. The proportion of female skilled workers in 2008 is 18%.

We work 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 StatoilHydro is gender neutral, meaning that men and women with the same position, experience and performance will be at the same salary levels. However, due to differences in types of positions and numbers of years' experience between women and men, some differences in compensation appear when comparing the general wage levels of men and women. On average, the earnings of female skilled workers are 93% of the earnings of their male colleagues. There are no significant differences between the earnings of female and male staff engineers.

3.7.3 Integration

In 2007 we completed the first phase of the integration between Statoil and Hydro. In 2008 we started the integration of our operational units.

One of our main actions in 2008 has been to complete the integration of our operating organisation in EPN, M&M and NG and to ensure a successful post-merger process for the parts of the organisation that were integrated in 2007.

During the first half of 2008, the integration planning committee, which consists of representatives from the corporate executive committee and the labour unions, has been involved in planning and designing the new operating model. From the 2nd quarter of 2008 and throughout 2009, project teams in the business areas that are involved in the second phase of the integration will complete the manning process and implement changes that the new operating model requires.

We have also carried out an integration monitoring survey which measures progress and satisfaction between our people and the merger process every three months. The results from 2008 indicate that the staff who were integrated in 2007 increasingly feel that they are being well taken care of, and that they have influence in decisions regarding their own working situation. For our people undergoing the integration in 2008 and 2009, the results are less positive.

Several activities have been carried out in order to ensure a successful post-merger process for the employees that were integrated in 2007. An integration research team, consisting of external researchers from the three research institutions International Research Institute of Stavanger, Institute for Research in Economics and Business Administration (SNF) and FAFO, have been assigned to deliver an independent evaluation of the entire integration process. The research programme will run for three years. So far, 13 professors and researchers, one PhD-candidates and 13 master students have been able to generate new knowledge and research about mergers and organisational outcomes based on data material and observations from the ongoing integration process in our company.

In 2009 one of our major post-merger activities will be to further strengthen the common and integrated company identity by launching our new vision and company name.

3.7.4 Unions and representatives

We emphasise the value of cooperation with our employees, and 69% of staff (StatoilHydro ASA) are members of a labour union. Our cooperation with employee representatives and labour unions is based on confidence and trust.

StatoilHydro emphasizes the value of cooperation with its employees, and 69% of the employees in the parent company are members of a labour union.

The way the company and the employee representatives work together is illustrated in the integration process between Statoil and Hydro described above.

The agreement with ICEM (Link to ICEM), which is an international federation that represents trade unions worldwide, was renewed in 2008. We were the first company in the oil and gas industry to sign this agreement. The cooperation with ICEM enables exchange of information and further development of good working practices within our operations worldwide. The content in the agreement reflects our policies and values on areas such as industrial relations, human rights and labour standards and HSE.

3.7.5 Organisational structure

The following table shows significant subsidiaries owned directly by the parent company, as well as the parent company's equity interest and the subsidiaries' country of incorporation. In each case our voting interest is equivalent to our equity interest.

Ownership in certain subsidiaries (in %)

Name	%	Country of incorporation	Name	%	Country of incorporation
AS Eesti Statoil	100	Estonia	Statoil Nigeria Outer Shelf AS	100	Norway
Latvija Statoil SIA	100	Lativia	Statoil Norge AS	100	Norway
Statholding AS	100	Norway	Statoil North Africa Gas AS	100	Norway
Statoil AB	100	Sweden	Statoil North Africa Oil AS	100	Norway
Statoil Angola Block 15 AS	100	Norway	Statoil North America Inc.	100	United States
Statoil Angola Block 15/06 Award AS	100	Norway	Statoil Orient Inc AG	100	Switerzland
Statoil Angola Block 17 AS	100	Norway	Statoil Polen Invest AS	100	Norway
Statoil Angola AS	100	Norway	Statoil Sincor AS	100	Norway
Statoil Apsheron AS	100	Norway	Statoil SP Gas AS	100	Norway
Statoil Asia Pacific Pte. Ltd.	100	Singapore	Statoil (UK) Ltd	100	United Kingdom
Statoil Azerbaijan Alov AS	100	Norway	Statoil Venezuela AS	100	Norway
Statoil Azerbaijan AS	100	Norway	StatoilHydro Canada Ltd.	100	Canada
Statoil BTC Finance AS	100	Norway	StatoilHydro Orinoco AS	100	Norway
Statoil Coordination Center N.V.	100	Belgium	StatoilHydro Petroleum AS	100	Norway
Statoil Danmark A/S	100	Denmark	StatoilHydro Russia AS	100	Norway
Statoil Deutschland GmbH	100	Germany	StatoilHydro Venture AS	100	Norway
Statoil do Brasil Ltda	100	Brazil	Statpet Invest AS	100	Norway
Statoil Exploration Ireland Ltd	100	Ireland	UAB Lietuva Statoil	100	Lithuania
Statoil Forsikring AS	100	Norway	Statoil Metanol ANS	82	Norway
Statoil Hassi Mouina AS	100	Algeria	Mongstad Refining DA	79	Norway
Statoil Iran AS	100	Norway	Mongstad Terminal DA	65	Norway
Statoil Nigeria AS	100	Norway	Tjeldbergodden Luftgassfabrikk DA	51	Norway
Statoil Nigeria Deep Water AS	100	Norway			

3.8 Oil and gas volumes

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

The following table sets out our Norwegian and international production of crude oil and natural gas for the periods indicated. The stated production volumes are the volumes that StatoilHydro is entitled to in accordance with conditions laid down in concession agreements and production sharing agreements, or PSAs. The production volumes are net of royalty oil paid in kind and of gas used for fuel and flare. Our production is based on our proportionate participation in fields with multiple owners and does not include production of the Norwegian State's oil and natural gas.

	For the year ended 31 December		
Production	**2008**	**2007**	**2006**
Norway			
Crude oil (mmbbls) [1]	**302**	299	315
Natural gas (bcf)	**1,348**	1,238	1,250
Natural gas (bcm)	**38.2**	35.1	35.4
Combined oil and gas (mmboe)	**542**	519	539
International			
Crude oil (mmbbls) [1]	**85**	92	70
Natural gas (bcf)	**121**	114	84
Natural gas (bcm)	**3.4**	3.2	2.4
Combined oil and gas (mmboe)	**106**	112	85
Total			
Crude oil (mmbbls) [1]	**386**	391	385
Natural gas (bcf)	**1,469**	1,352	1,335
Natural gas (bcm)	**41.6**	38.3	37.8
Combined oil and gas (mmboe)	**648**	632	624

[1] Crude oil includes natural gas liquids (NGL) and condensate production. NGL includes both LPG and naphta

Sales Volume Information

In addition to our own volumes, we market and sell oil and gas owned by the Norwegian State through the Norwegian State's share in production licences, known as the State's direct financial interest, or SDFI, together with our own production. For additional information see section 3.13 Operational review-Related party transactions. The following table sets out SDFI and StatoilHydro sales volume information for crude oil and natural gas, as applicable, for the periods indicated. The SDFI volumes shown below include royalty oil we sell on behalf of the Norwegian State. The payment of royalty obligations on the NCS was abolished on 31 December 2005. The StatoilHydro natural gas sales volumes include equity volumes sold by Natural Gas, natural gas volumes sold by International E&P and ethane volumes.

Sales Volumes	For the year ended 31 December 2008	2007	2006
StatoilHydro: [1]			
Crude oil (mmbbls) [2]	**372**	395	382
Natural gas (bcf)	**1387**	1257	1334
Natural gas (bcm) [3]	**39.3**	35.6	37.8
Combined oil and gas (mmboe)	**619**	619	620
Third party volumes: [4]			
Crude oil (mmbbls) [2]	**242**	240	200
Natural gas (bcf)	**127**	177	152
Natural gas (bcm) [3]	**3.6**	5.0	4.3
Combined oil and gas (mmboe)	**265**	271	227
SDFI assets owned by the Norwegian State (including royalty):			
Crude oil (mmbbls) [2]	**213**	235	254
Natural gas (bcf)	**1440**	1327	1168
Natural gas (bcm) [3]	**40.8**	37.6	33.1
Combined oil and gas (mmboe)	**470**	472	462
Total			
Crude oil (mmbbls) [2]	**827**	869	836
Natural gas (bcf)	**2955**	2760	2655
Natural gas (bcm) [3]	**83.7**	78.2	75.2
Combined oil and gas (mmboe)	**1353**	1361	1309

[1] The StatoilHydro volumes included in the table above assume that volumes sold were equal to lifted volumes in the relevant year. This differs from the sales volumes reported elsewhere in this report by the Oil Trading and Supplies (OTS) organisation in the Manufacturing and Marketing segment in that such volumes include volumes still in inventory or transit held by other reporting entities within the group. Excluded from such volumes are volumes lifted by the International E&P but not sold by OTS, and volumes lifted by E&P Norway or International and still in inventory or in transit.

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

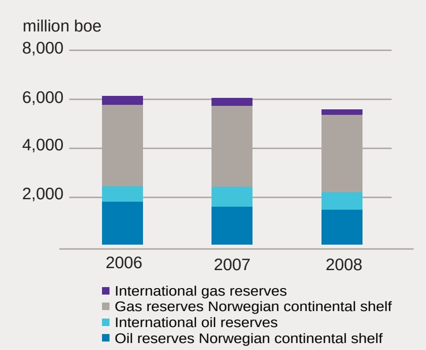
[3] At a gross calorific value (GCV) of 40 MJ/scm.

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

3.9 Proved oil and gas reserves

Proved oil and gas reserves were estimated to be 5584 mmboe at the end of 2008, compared to 6010 mmboe at the end of 2007.

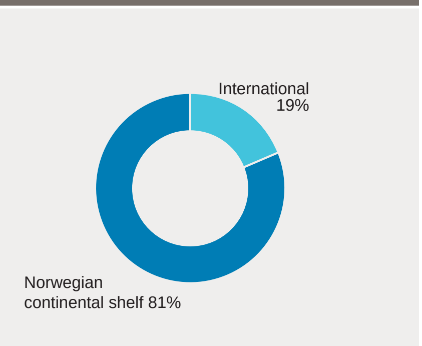
PROVED OIL AND GAS RESERVES



Proved reserves and changes to proved reserves are estimated in accordance with SEC definitions. The reserves replacement ratio is defined as the sum of proved reserves additions and revisions, divided by produced volumes in any given period.

Changes in proved reserves estimates most commonly originate from revisions of estimates due to observed production performance, extensions of proved areas through drilling activities, or inclusion of proved reserves in new discoveries through sanctioning of development projects. These are sources of proved reserves additions that result from continuous business processes, and could be expected to continue to add reserves at some level in the future. Proved reserves may also be added or subtracted through acquisitions or disposals of assets.

DISTRIBUTION OF PROVED RESERVES



Changes in proved reserves may also originate from factors outside management control, such as changes in oil and gas prices. While lower oil and gas prices normally allow less oil and gas to be recovered from the accumulations, StatoilHydro's proved oil and gas reserves under PSAs and similar contracts will generally increase as a result. StatoilHydro will receive larger quantities of oil and gas under the cost recovery and profit sharing arrangements of these contracts as a result of the decreased oil and gas prices. These changes are included in the revisions category in the table below.

Reserves in new discoveries are normally booked only when regulatory approval has been received, or when such approval is imminent. Reserve additions from new discoveries booked in 2008 are expected to be produced in the period from year 2009 to 2021. Reserves from new discoveries, upward revisions of reserves and purchases of proved reserves are expected to contribute to maintaining proved reserves in future years.

Below is a table showing the reserves additions in each change category relating to the reserve replacement ratio for the years 2008, 2007 and 2006.

	For the year ended 31 December		
(million boe)	**2008**	**2007**	**2006**
Revisions and improved recovery	**213**	325	300
Extensions and discoveries	**17**	215	86
Purchase of petroleum-in-place	**69**	0	0
Sales of petroleum-in-place	**(10)**	0	(3)
Change in interest *	**(68)**	0	0
Total reserve additions	**222**	541	383
Production	**(648)**	(632)	(624)
Net change in proved reserves	**(426)**	(91)	(241)

* Reduction of interest in Petrocedeño.

A total of 222 mmboe proved reserves was added during 2008, of which 186 mmboe were proved developed reserves. The remaining 36 mmboe were proved undeveloped reserves.

The reserves replacement ratio was 34% in 2008, compared to 86% in 2007. The decrease in the reserve replacement ratio in 2008 compared to 2007 is mainly due to 2008 being a year with small reserve additions from sanctions of new development projects and high production. The average replacement rate for the last three years was 60%, including purchases, sales and reduction of sharehold interest in Petrocedeño.

Reserves replacement ratio (three-year average)	For the year ended 31 December 2008	2007	2006
Corporate	**0.60**	0.81	0.76
E&P Norway	**0.51**	0.78	0.62
International E&P	**1.10**	0.98	1.74

The usefulness of the reserves replacement ratio is limited by the volatility of oil prices, the influence of oil and gas prices on PSA reserve booking, the sensitivity related to the timing of project sanctions, and the time lag between exploration expenditure and booking of reserves.

We review our petroleum reserves in the course of business as new information becomes available. This information can be related to remaining reserves, existing production performance, decisions related to development, production, acquisition and divestment of reserves and changes in economic conditions. In addition, information on proved oil and gas reserves, standardised measure of discounted net cash flows related to proved oil and gas reserves, and other information related to proved oil and gas reserves reported in note 34 - Supplementary oil and gas information - to our Consolidated Financial Statements, is collected and checked for consistency and conformity with applicable standards by a central group that is independent of the exploration and production business units.

Although this group reviews the information centrally, each asset team is responsible for ensuring that it is in compliance with the requirements of the SEC and our corporate standards. Before presenting the aggregated results for approval to the management responsible for the relevant business units and the Chief Executive Officer, this central group asks DeGolyer and MacNaughton, independent petroleum engineering consultants, to perform an independent evaluation of proved reserves. This was last performed as of 31 December 2008.

The results obtained by DeGolyer and MacNaughton do not differ materially from those reported by us when compared on the basis of net equivalent barrels of oil. DeGolyer and MacNaughton have provided us with a summary letter report describing their procedures and conclusions, a copy of which is included in the following report section.

Reserve engineering is a process of forecasting the recovery and sale of oil and gas from a reservoir and is in part subjective. It is clearly associated with considerable uncertainty, both positive and negative. The accuracy of any reserve information is a function of the quality of available data and of engineering and requires interpretation and judgment. The requirements of the SEC with respect to the calculation of proved reserves set a standard for estimating reserves, which results in amounts that are reasonably certain technically and consistent with the economic, regulatory and operating conditions at the time the estimates are made. See note 34 - Supplementary oil and gas information - to our Consolidated Financial Statements, for further details on our proved reserves.

3.9.1 Report of DeGolyer and MacNaughton

DeGolyer and MacNaughton, independent petroleum engineering consultants, have performed an independent evaluation of StatoilHydro's proved reserves as of 31 December 2008. A copy of a summary letter report from DeGolyer and MacNaughton, describing their procedures and conclusions, is included below.

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 13, 2009

StatoilHydro ASA
Forusbeen 50
N-4035 Stavanger
Norway

Gentlemen:

Pursuant to your request, we have prepared estimates of the proved oil, condensate, liquefied petroleum gas (LPG), and sales gas reserves, as of December 31, 2008, of certain properties with interests owned by StatoilHydro ASA (StatoilHydro) in Algeria, Angola, Azerbaijan, Brazil, Canada, China, Iran, Ireland, Libya, Nigeria, Norway, Russia, the United Kingdom, the United States, and Venezuela. The estimates are discussed in our "Report as of December 31, 2008 on Proved Reserves attributable to StatoilHydro ASA in Certain Properties" (the Report). We also have reviewed StatoilHydro's estimates of reserves, as of December 31, 2008, of the same properties included in the Report.

In our opinion, the information relating to proved reserves estimated by us and referred to herein has been prepared in accordance with Paragraphs 10–13, 15, and 30(a)–(b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the Financial Accounting Standards Board and Rules 4– 10(a) (1)–(13) of Regulation S–X of the United States Securities and Exchange Commission (SEC).

StatoilHydro represents that its estimates of the proved reserves, as of December 31, 2008, attributable to StatoilHydro's interests in the properties included in the Report are as follows, expressed in millions of barrels (MMbbl), billions of cubic feet (Bcf), and millions of barrels of oil equivalents (MMboe):

Oil, Condensate, and LPG (MMbbl)	Sales Gas (Bcf)	Oil Equivalent (MMboe)
2,201	18,984	5,584

Note: Gas is converted to oil equivalent using a factor of 5,612 cubic feet of gas per 1 barrel of oil equivalent.

StatoilHydro has advised us that its estimates of proved oil, condensate, LPG, and natural gas reserves are in accordance with the rules and regulations of the SEC. It is our opinion that the guidelines and procedures that StatoilHydro has adopted to prepare its estimates are in accordance with generally accepted petroleum reserves evaluation practices and are in accordance with the requirements of the SEC.

Our estimates of the proved reserves, as of December 31, 2008, attributable to StatoilHydro's interests in the properties included in the Report are as follows, expressed in millions of barrels (MMbbl), billions of cubic feet (Bcf), and millions of barrels of oil equivalents (MMboe):

Oil, Condensate, and LPG (MMbbl)	Sales Gas (Bcf)	Oil Equivalent (MMboe)
2,257	18,889	5,623

Note: Gas is converted to oil equivalent using a factor of 5,612 cubic feet of gas per 1 barrel of oil equivalent.

In comparing the detailed reserves estimates prepared by us and those prepared by StatoilHydro for the properties involved, we have found differences, both positive and negative, in reserves estimates for individual properties. These differences appear to be compensating to a great extent when considering the reserves of StatoilHydro in the properties included in the Report, resulting in overall differences not being substantial. It is our opinion that the reserves estimates prepared by StatoilHydro on the properties reviewed by us and referred to above, when compared on the basis of net equivalent million barrels of oil, in aggregate, do not differ materially from those prepared by us.

Submitted,

DeGOLYER and MacNAUGHTON

/s/ Lloyd W. Cade

Lloyd W. Cade, P.E.
Senior Vice President
DeGolyer and MacNaughton

3.10 Regulation

The principal Norwegian legislation applying to our petroleum activities in Norway are the Norwegian Petroleum Act and the Norwegian Petroleum Taxation Act.

The principal Norwegian legislation applying to our petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of November 29, 1996 (the "Petroleum Act"), and the regulations promulgated thereunder, as well as the Norwegian Petroleum Taxation Act of June 13, 1975 (the "Petroleum Taxation Act"). The Petroleum Act states the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that the exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorized to award licenses concerning the petroleum activities. We are dependent upon the Norwegian State for its approval of our NCS exploration and development projects and applications for production rates for individual fields.

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy is responsible for resource management and for administering petroleum activities on the NCS. The main task of the Ministry of Petroleum and Energy is to ensure that petroleum activities are conducted in accordance with the applicable legislation, the policies adopted by the Norwegian parliament or Storting, and relevant decisions of the Norwegian State. The Ministry of Petroleum and Energy primarily implements petroleum policy through its power to administer the award of licenses and approve operators' field and pipeline development plans, as well as petroleum transport and gas sales contracts. Only those plans that conform to the policies and regulations set by the Storting are approved. As set forth in the Petroleum Act, if a plan involves an important principle or will have a significant economic or social impact, it must also be submitted to the Storting for acceptance before being approved by the Ministry of Petroleum and Energy.

We are not required to submit any decisions relating to our operations to the Storting. However, the Storting's role with respect to major policy issues in the petroleum sector may affect us in two ways: first, when the Norwegian State acts in the capacity as the majority owner of our shares and, second, when the Norwegian State acts in its capacity as regulator:

- The Norwegian State held 67% of our ordinary shares as at 5 March, 2009. Norwegian State's shareholding in StatoilHydro is managed by the Ministry of Petroleum and Energy. The Ministry of Petroleum and Energy will normally determine how the Norwegian State will vote its shares on proposals submitted to general meetings of the shareholders. However, in certain exceptional cases, it may be necessary for the Norwegian State to seek approval from the Storting before voting on a certain proposal. This will normally be the case if we issue additional shares and such issuance would significantly dilute the Norwegian State's holding, or if such issuance would require a capital contribution from the Norwegian State in excess of government mandates. It is not possible to predict how the Norwegian Storting will decide on a proposal for issuance of additional shares which would either significantly dilute its holding of StatoilHydro shares or require a capital contribution from it in excess of governmental mandates. A decision by the Norwegian State against our proposal to issue additional shares would prevent us from raising additional capital in this manner and could adversely affect our ability to pursue business opportunities and to further develop the company.
- The Norwegian State exercises important regulatory powers over us, as well as over other companies and corporations. As part of our business, we, or the partnerships to which we are a party, frequently need to apply for licenses and other approvals of various types from the Norwegian State. In respect of certain important applications, such as approvals of major plans for operation and development of fields, the Ministry of Petroleum and Energy must obtain the consent of the Storting before it can approve our or the relevant partnership's application. This may take additional time and affect the content of the decision. Although StatoilHydro is majority-owned by the Norwegian State, it does not receive any preferential treatment with respect to licenses granted by or under any other regulatory rules enforced by the Norwegian State.

Although Norway is not a member of the European Union, or EU, it is a member of the European Free Trade Association (EFTA). The EU and its member states have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, with the members of EFTA (except Switzerland).

The EEA Agreement makes certain provisions of EU law binding as between the states of the EU and the EFTA states, and also as between the EFTA states themselves. An increasing volume of regulation affecting us is adopted within the EU and is then applied to Norway under the EEA Agreement. As a Norwegian company operating both within EFTA and the EU, our business activities are regulated by both EEA law and EU law to the extent that EU law has been accepted into EEA law under the EEA Agreement.

3.10.1 The Norwegian licensing system

The most important type of license awarded under the Petroleum Act is the production licence, and the Ministry of Petroleum and Energy holds executive discretionary power to award a production licence and to determine the terms of that licence.

In 2008 we participated in 346 production license on the NCS. As a participant in licenses, we are subject to the regulations of the Norwegian licensing system.

The most important type of license awarded under the Petroleum Act is the production licence, and the Ministry of Petroleum and Energy holds executive discretionary power to award a production licence and to determine the terms of that licence. The Government is not entitled to award us a licence in an area until the Storting has decided to open the area in question for exploration. The terms of our production licenses are determinated by the Ministry of Petroleum.

A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Notwithstanding the exclusive rights granted under a production licence, the Ministry of Petroleum and Energy has the power, in exceptional cases, to permit third parties to carry out exploration in the area covered by a production licence. For a list of our shares in production licences, see the report section 3.1.5 Operational review-E&P Norway-Production.

Production licences are normally awarded through licensing rounds. The first licensing round for NCS production licences was announced in 1965. The award of the first licences covered areas in the North Sea. Over the years the award of licences has moved northward and covers areas both in the Norwegian Sea and in the Barents Sea. In recent years, the principal licensing rounds have mainly included licences in the Norwegian Sea. Beginning in 2003, the Norwegian government changed its policy on mature areas and introduced a scheme for award of production licences named "Award in Predefined Areas" (APA) in mature parts of the Norwegian Continental Shelf. The award of licences in the predefined areas has taken place every year since 2003. The Ministry of Petroleum and Energy has, in a report to the Storting, announced that this policy will continue.

The Norwegian State accepts licence applications from individual companies and group applications. This allows us to choose our exploration and development partners.

Production licences are awarded to joint ventures. As is the case for most fields on the NCS, our production activities are conducted through joint venture arrangements with other companies and in some cases with the Norwegian State through its wholly-owned company Petoro. The members of the joint venture are jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the license. Once a production licence is awarded, the licensees are required to enter into a joint operating agreement and an accounting agreement which regulate the relationship between the partners. The Ministry of Petroleum and Energy decides the form of the joint operating agreements and accounting agreements.

The governing body of the joint venture is the management committee. Each member is entitled to one seat on the management committee. The management committee's tasks are set out in the joint operating agreement and include setting guidelines for the operator of the field, exercising control over the activities of the operator, and making decisions on the activities of the joint venture. Votes in the management committee are counted by a combination of the number of members in the joint venture and their ownership interest. The number of votes required to make a decision varies from licence to licence, but a decision is normally reached when a certain number of the members and a percentage of the ownership interests, specified individually in each licence, have voted in favour of a proposal. The voting rules are structured so that a licensee holding more than 50% of a licence normally cannot vote through a proposal on its own, but will need the support of one or more of the other licensees. In licences awarded since 1996 where the SDFI holds an interest, the Norwegian State, acting through the SDFI management company, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence as to the Norwegian State's exploitation policies or financial interests. This veto right has never been used.

Under the joint operating agreements covering licences awarded prior to 1996, the management company that supervises the Norwegian State's SDFI interest, Petoro AS, has the power, with certain exceptions, to make decisions unilaterally in matters which are assumed to be of political or principal importance, or which may have significant social or socio-economic consequences, if Petoro AS is acting under the direction of its shareholder. Prior to the establishment of the SDFI management company, StatoilHydro held this right, which was exercised three times, most recently in 1988. In autumn 2002, the Storting began to allow individual license groups to substitute this special voting rule for the SDFI with a veto rule similar to the veto rules which have applied to licences awarded since 1996. Such a substitution is subject to approval from the Ministry of Petroleum and Energy.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. In 2008 we were the operator for 42 of our 48 production licenses. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement. Under the joint operating agreement, an operator may normally terminate its engagement upon six months' notice. The management committee may, however, with the consent of the Ministry of Petroleum and Energy, instruct the operator to continue performing its duties until a new operator has been appointed. The management committee can terminate the operator's engagement upon six months' notice on an affirmative vote by all members of the management committee other than the operator. A change of operator requires the consent of the Ministry of Petroleum and Energy. In special cases the Ministry of Petroleum and Energy can order a change of operator.

Licensees are required to submit a plan for development and operation, or PDO, to the Ministry of Petroleum and Energy for approval. In respect of fields of a certain size, the Storting has to accept the PDO before it is formally approved by the Ministry of Petroleum and Energy. Until the PDO has been approved by the Ministry of Petroleum and Energy, the licensees cannot, without the prior consent of the Ministry of Petroleum and Energy, undertake material contractual obligations or commence construction work.

Production licences are normally awarded for an initial exploration period which is typically six years, but which can be either for a shorter period or for a maximum period of ten years. During this exploration period the licensees must meet a specified work obligation set out in the licence. The work obligation will typically include seismic surveying and/or exploration drilling. If the licensees fulfil the obligations set out in the production licence, they are entitled to require that the licence be prolonged for a period specified at the time when the licence is awarded, typically 30 years. The right to prolong the licence does not apply as a main rule to the whole of the geographical area covered by the initial licence, but only to a percentage, typically 50%. The size of the area which must be relinquished is determined at the time the licence is awarded. In special cases, the Ministry of Petroleum and Energy may extend the duration of a production licence.

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

The Norwegian State may, if important public interests are at stake, direct us and other licensees on the NCS to reduce production of petroleum. From 15 July 1987 until the end of 1989, licensees were directed to curtail oil production by 7.5%. Between 1 January 1990 and 30 June 1990, licensees were directed to curtail oil production by 5%. In 1998, the Norwegian State resolved to reduce Norwegian oil production by about 3%, or 100 mbbl per day. In March 1999, the Norwegian State decided to increase the reduction to 200 mbbl per day. In the second quarter of 2000, the reduction was brought back to 100 mbbl per day. On 1 July 2000, this restriction was removed. By a royal decree of 19 December 2001, the Norwegian government decided that Norwegian oil production would be reduced by 150 mbbl per day from 1 January 2002 until 30 June 2002. This amounted to approximately a 5% reduction in output.

Licensees may buy or sell interests in production licences subject to the consent of the Ministry of Petroleum and Energy and the approval of the Ministry of Finance of a corresponding tax treatment position. The Ministry of Petroleum and Energy must also approve indirect transfers of interest in a licence, including changes in the ownership of a licensee, if they result in a third party obtaining a decisive influence over the licensee. There are in most licences no pre-emption rights in favour of the other licensees. The SDFI, or the Norwegian State, as appropriate, however, still holds pre-emption rights in all licences. All of our licensing transactions entered into in 2008 were approved by the Ministry of Petroleum and Energy and the Ministry of Finance.

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for transport and utilization of petroleum. When applying for such licences, the owners, which are in practice licensees under a production licence, must prepare a plan for installation and operation. Licences to establish facilities for transport and utilization of petroleum will normally be awarded subject to certain conditions. Typically, these conditions require the facility owners to enter into a participants' agreement. The ownership of most facilities for transport and utilization of petroleum in Norway and on the NCS are organized as a joint venture of a group of license holders, and the participants' agreements are similar to the joint operating agreements entered into among the members of joint ventures holding production licenses. All of our applications for facility licenses submitted in 2008 have been granted by the Ministry of Petroleum and Energy.

Licensees are required to prepare a decommissioning plan before a production licence or a licence to establish and use facilities for transportation and utilization of petroleum expires or is relinquished, or the use of a facility ceases. The decommissioning plan must be submitted to the Ministry of Petroleum and Energy no sooner than five and no later than two years prior to the expiry of the licence or the cessation of the use of the facility, and must include a proposal for the disposal of facilities on the field. On the basis of the decommissioning plan, the Ministry of Petroleum and Energy makes a decision as to the disposal of the facilities.

The Norwegian State is entitled to take over the fixed facilities of the licensees when a production licence expires, is relinquished or revoked. In respect of facilities on the NCS, the Norwegian State decides whether any compensation will be payable for facilities thus taken over. If the Norwegian State should choose to take over onshore facilities, the ordinary rules of compensation in connection with expropriation of private property apply. None of our production licenses expired in 2008 and none are due to expire in 2009.

Licences for the establishment of facilities for transport and utilization of petroleum typically include a clause whereby the Norwegian State can require that the facilities be transferred to it free of charge at the expiration of the licence period.

3.10.2 Gas sales and transportation

StatoilHydro markets gas from the Norwegian continental shelf on our own and the Norwegian state's behalf. Gas is transported through the Gassled pipeline network to customers in Europe.

Gas sales contracts with buyers for the supply of Norwegian gas are concluded individually with each company.

The upstream gas transportation system consists of several pipelines owned by a joint venture called Gassled. We have a 32.10% interest in Gassled (32.88% including our indirect interest through our 28.58% holding in Norsea Gas AS) and are responsible for the technical operation of the majority of export pipelines and onshore plants in the processing and transportation systems for Gassled; see section 3.3.4 Operational review-Natural Gas-Norway's gas transport system.

The Norwegian authorities have issued regulations by a royal decree of 20 December 2002 for access to and tariffs for capacity in the upstream gas transportation system. There are three main considerations behind the regulations. Firstly the regulations, together with the law adopted by the Storting in June 2002, implement the Gas Directive of the European Union. Secondly, they established a system for access to the upstream gas transportation system that is compatible with company-based gas sales from the NCS. Thirdly, they provided for the new ownership structure of the upstream gas transportation system (Gassled).

Parts of the regulations have a general application and parts - including the tariffs - are applicable only to the upstream gas transportation system owned by the Gassled joint venture. The regulations establish the main principles for access to the upstream gas transportation system. The access regime consists of a regulated primary market where the right to book spare capacity, in accordance with regulations, is allocated to users with need requisite need for transportation of natural gas. Furthermore, the access regime consists of a secondary market where the capacity can be transferred between the users after the allocation in the primary market if the need for transportation changes.

The capacity in the primary market is released and booked through Gassco AS on the internet. Spare capacity is released for pre-defined time periods at announced points in time and with specific time limits for reservations. If the reservations exceed the spare capacity, the spare capacity will be allocated based on a distribution formula. However, in case of scarce capacity, consideration must first be given to the owners' duly substantiated needs for capacity, limited to twice the owner's equity interest in the upstream pipeline network.

Based on authorisation given under the regulations, tariffs for use of capacity in Gassled are determined by the Ministry of Petroleum and Energy. The Ministry's policy for determining the tariffs is to avoid excessive returns being created on the capital invested in the transportation system, allowing the return on the Norwegian petroleum activity to be taken out on the fields instead of in the transportation systems. The tariffs are to be paid for booked capacity and not in respect of the actually transported volume.

3.10.3 Gas directive of the European Union

The EU Gas Directive, which has been included in the EEA Agreement and incorporated into Norwegian legislation, regulates the European gas market in conjunction with the gas Transmission Access Regulation of 2005.

Most of our gas is sold under long-term gas contracts to customers in the EU, a gas market that is continuing to be affected by changes in EU regulations and the implementation of such regulations in EU member sates. Such regulation affects our ability to expand or even maintain our current market position, as quantities sold under our gas sales contracts may be subject to a material change in gas prices as a result of the regulations under the EU Gas Directive.

The Directive requires that all consumers in Europe should be able to choose their energy supplier beginning in July 2007. Fundamental changes to this directive and regulation were proposed by the European Commission in September 2007 with a specific focus on the separation of ownership of transmission assets from supply activities. The objective of these proposals is to increase competition in national markets and integrate them into regional and eventually a single EU-wide market for natural gas. The final form of these proposals are as yet unknown and are expected to be developed further throughout 2009. It is difficult to predict the effect liberalisation measures will have on the evolution of gas prices, but the main objective of the single gas market is to bring greater choice and reduced prices for customers through increased competition.

3.10.4 HSE regulation

Our petroleum operations in Norway are subject to extensive regulation with regard to health, safety and the environment, or HSE.

Under the Petroleum Act, which is administered by the Ministry of Labour and Government Administration, our petroleum operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in accordance with technological developments. StatoilHydro established a system for monitoring the technical safety of its plants in 2001, and, as part of this system, it collects and interprets information from its operating activities and incorporates risk management in its operating activities.

We are required to maintain at all times a plan to deal with emergency situations in our petroleum operations. During an emergency, the Ministry of Labour and Government Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the account of the licensees.

The Petroleum Safety Authority Norway (PSA) has the regulatory responsibility for safety, emergency preparedness and the working environment for all petroleum-related activities. The PSA's sphere of responsibility also includes supervision of safety, emergency preparedness and the working environment at the petroleum facilities and connected pipeline systems on land.

In our capacity as a holder of licences under the Petroleum Act, we are subject to strict statutory liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licenses. This means that anyone who suffers damage or loss as a result of pollution caused by any of our NCS licence areas can claim compensation from us without needing to demonstrate that the damage is due to any fault on our part. If the pollution is caused by a force majeure event, a Norwegian court may reduce the level of damages to the extent it considers reasonable.

3.10.5 Taxation of StatoilHydro

We are subject to ordinary Norwegian corporate income tax as well as to a special petroleum tax relating to our offshore activities. We are also subject to a special carbon dioxide emissions tax and, from 2007, a nitrogen oxide fee.

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

Corporate income tax. Our profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The corporate income tax rate is currently 28%. Our profits are computed in accordance with ordinary Norwegian corporate income tax rules, subject to certain modifications that apply to companies engaged in petroleum operations. Gross revenue from oil production and the value of lifted stocks of oil are determined on the basis of norm prices. Norm prices are decided on a monthly basis by the Petroleum Price Board, a body whose members are appointed by the Ministry of Petroleum and Energy, and published quarterly. The Petroleum Taxation Act provides that the norm prices shall correspond to the prices that could have been obtained in case of a sale of petroleum between independent parties in a free market. When adopting norm prices, the Petroleum Price Board takes into consideration a number of factors, including spot market prices and contract prices within the industry.

The maximum rate for depreciation of development costs related to offshore production installations and pipelines is 16.67% per year. The depreciation starts when the cost is incurred. Exploration costs may be deducted in the year in which they are incurred. Beginning in 2007, financial costs related to the offshore activity are calculated directly based on a formula set in the Petroleum Tax Act. The financial costs deductible against the offshore tax regime are the total financial costs multiplied by 50% of tax values divided by average interest bearing debt. All other financial costs and income are allocated to the onshore tax regime.

Any tax losses may be carried forward indefinitely against subsequent income earned. Fifty percent of losses relating to activity conducted onshore in Norway may be deducted from NCS income subject to the 28% tax rate. Losses from foreign activities may not be deducted against NCS income. Losses from offshore activities are fully deductible against onshore income.

By use of group contributions between Norwegian companies in which we hold more than 90% of the shares and the votes, tax losses and taxable income can be offset to a great extent. Group distributions are not deductible in our offshore income.

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividend amounts received and this is subject to the standard 28% income tax. Dividends from low-tax countries or portfolio investments outside the EEA will under certain circumstances be subject to the standard 28% income tax based on the full amounts received.

Capital gains from realisation of shares are taxable where the basis for taxation is 3 % of the gain which is subject to the standard 28% income tax. Capital losses from realisation of shares are not deductible. Exemptions exist for shares held in companies domiciled in low-tax countries or portfolio investments outside the EEA where capital gains under certain circumstances will be subject to the standard 28% income tax and capital losses will be deductible.

Special petroleum tax. 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 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 capitalized 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. Unused uplift may be carried forward indefinitely.

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

Carbon dioxide emissions tax. A special carbon dioxide emissions tax applies to petroleum activities on the NCS. The tax is NOK 0.45 for 2008 and NOK 0.46 for 2009 per standard cubic metre of gas burned or directly released and per litre of oil burned. From 2008, companies operating on the NCS have to buy quotas to cover the carbon dioxide emissions from the petroleum activities.

Nitrogen oxide fee. Beginning on 1 January 2007, the Norwegian government introduced a nitrogen oxide fee applicable to emissions of nitrogen oxide on the NCS. The fee is NOK 15.39 per kilogram of nitrogen oxide for 2008 and NOK 15.85 for 2009.

Alternatively to pay the nitrogen oxygen fee, companies may voluntarily agree to contribute to an industry nitrogen oxygen fund for the years 2008-2010. The contribution to the fund is NOK 11 per kilogram of nitrogen oxide emissions. We have entered into an agreement to contribute to the fund.

Area fee. After the expiration of the initial exploration period, the holders of production licences are required to pay an area fee. The amount of the area fee is set out in regulations promulgated under the Petroleum Act. In respect of most of the production licences, the initial annual area fee is currently NOK 7000 per square kilometre. The annual area fee is increased yearly by NOK 7000 until it reaches NOK 70,000 per square kilometre.

Taxation outside Norway

StatoilHydro's international petroleum activities are subject to tax according to local tax legislation. Fiscal regulation of our upstream operations is generally based on corporate income tax regimes and/or production sharing agreement (PSA) regimes. Royalties may be applicable in each regime.

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

Production sharing agreements. Under a PSA, the host government typically retains the right to the hydrocarbons in place. The contractor under a PSA normally receives a share of the oil produced to recover its costs, and additionally is entitled to an agreed share of the oil as profit. The allocation of profit oil between the state and the contractors is typically increasing towards the state based on a success factor, such as surpassing certain specified internal rates of return, production rates or accumulated production. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery and then are entitled to recover those costs during the producing phase. Fiscal provisions in a PSA contract are, to a large extent, negotiable and are unique to each PSA. Contractors to a PSA are generally insulated from legislative changes to a country's general tax laws.

Income tax regimes. Under an income tax/royalty regime, companies are granted licenses by the government to extract petroleum, and the state may be entitled to royalties in addition to tax based on the company's net taxable income from production. The fiscal terms surrounding these licenses are, in general, not negotiable and the company is subject to legislative changes to the tax laws.

3.10.6 The Norwegian state's participation

The Norwegian state's direct participation in petroleum operations on the NCS

The Norwegian State's policy as an owner of shares of StatoilHydro has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

Initially, the Norwegian State's participation in petroleum operations was organised mainly through us. In 1985, the Norwegian State established the State's direct financial interest, or SDFI, through which the Norwegian State has taken direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which we also hold interests.

As a result of changes in global markets and competitive conditions in the petroleum industry, the Norwegian State implemented a strategic review of its oil and gas policy in 2000. Based on the results of this strategic review, the Norwegian State prepared a plan to restructure its petroleum holdings on the NCS that was approved by the Storting on 26 April 2001. The key elements of the restructuring plan led to:

- the partial privatization of Statoil
- a restructuring of the Norwegian State's SDFI assets, including the sale of SDFI assets to us and to other oil and gas companies and an exchange of interests in certain oil and gas infrastructure between the SDFI and us
- the establishment of procedures to ensure that, as long as the Norwegian State instructs us to do so, we will continue to market and sell the State's oil and gas, together with our oil and gas
- the transfer of responsibility over and management of the SDFI's assets from us to a new company named Petoro AS which is wholly owned by the Norwegian State; and
- the transfer of operational responsibility over certain pipelines on the NCS from us to Gassco AS which is wholly owned by the Norwegian State.

3.10.7 Marketing and sale of SDFI oil and gas

Historically, we have marketed and sold the Norwegian State's oil and gas as a part of our own production, and the Norwegian State has elected to continue this arrangement.

Accordingly, at an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised our articles of association by adding a new article which requires us to continue to market and sell the Norwegian State's oil and gas together with our own oil and gas in accordance with an instruction established in shareholder resolutions in effect from time to time. At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instructions referred to in the new article. This resolution is referred to as the owner's instruction.

The Norwegian State has a coordinated ownership strategy to maximise the aggregate value of its ownership interests in StatoilHydro and the Norwegian State's oil and gas. This is reflected in the owner's instruction, which contains a general requirement that, in our activities on the NCS, we are required to take account of these ownership interests in decisions that may affect the execution of this marketing arrangement.

The owner's instruction sets forth specific terms for the marketing and sale of the Norwegian State's oil and gas. The principal provisions of the owner's instruction are as set out below.

Objectives.
The overall objective of the marketing arrangement is to obtain the highest possible total value for our oil and gas and the Norwegian State's oil and gas and ensure an equitable distribution of the total value creation between the Norwegian State and us. In addition, the following considerations are important:

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

Our tasks. Our tasks under the owner's instruction are to market and sell the Norwegian State's oil and gas and to carry out all necessary tasks, other than those carried out jointly with other licensees under the production licence, in relation to the marketing and sale of the Norwegian State's oil and gas, including, but not limited to, the responsibility for processing, transport and marketing. In the event that the owner's instruction is terminated, in whole or in part, by the Norwegian State, the owner's instruction provides a mechanism under which contracts for the marketing and sale of the Norwegian State's oil and gas to which we are a party may be assigned to the Norwegian State or its nominee. Alternatively, the Norwegian State may require that the contracts be continued in our name, but to the effect that in the underlying relationship between the Norwegian State and us, the Norwegian State receives all rights and obligations related to the Norwegian State's oil and gas.

Costs. The Norwegian State does not pay us specific consideration for executing these tasks, but the Norwegian State reimburses us for its proportionate share of certain costs, which under the owner's instruction may be our actual costs or an amount specifically agreed.

Price mechanisms. For sales of the Norwegian State's natural gas, both to us and to third parties, the payment to the Norwegian State is based on either achieved prices, a net back formula or market value. We now purchase all of the Norwegian State's oil and NGL. Pricing of the crude oil is based on market reflective prices. NGL prices are based on either achieved prices, market value or market reflective prices.

Lifting mechanism. As part of the coordinated ownership strategy, a lifting mechanism for the Norwegian State's and our oil and gas is established in accordance with rules set out in the owner's instruction.

To ensure a neutral weighting between the Norwegian State's and our own natural gas volumes, a list has been established for deciding the priority between each individual field. To decide the ranking, a mathematical optimisation model is used which describes existing and planned production facilities, infrastructure and processing terminals where the Norwegian State and we have ownership interests. The list yields a result giving the highest total net present value for the Norwegian State's and our oil and gas. In the evaluation, the following objective criteria shall, among other things, apply:

- the effect of the draw on the depletion rate
- identification of time critical fields
- influence on oil/liquid fields with associated gas needing gas disposal; and
- free capacity and flexibility in transportation systems and onshore facilities.

The various fields are ranked in accordance with the assumed total value creation for the Norwegian State and us, assuming all of the fields meet our profitability requirements if we participate as a licensee, and the Norwegian State's profitability requirements if the State is a licensee. The list is updated annually or more frequently if incidents occur that may significantly influence the ranking. Within each individual field where both the Norwegian State and we are licensees, the Norwegian State and we will deliver volumes and share income in accordance with our respective participating interests.

The Norwegian State's oil and NGL are lifted together with our oil and NGL in accordance with applicable lifting procedures for each individual field and terminal.

Withdrawal or Amendment. The Norwegian State may utilise its position as majority shareholder of StatoilHydro at any time to withdraw or amend the instruction requiring us to market and sell the SDFI oil and natural gas together with our own.

3.10.8 Petoro AS

Petoro AS - the SDFI management company

In 1985, the Norwegian State began taking a direct financial interest in production licences through the establishment of the SDFI, and in 2001, a new state-owned company, Petoro, was established to administer SDFI assets.

From the establishment of Statoil in 1972 and until 1 January 1985, the participation of the Norwegian State in production licences and facilities for transport and utilisation of petroleum took place entirely through Statoil. As of 1 January 1985, the Norwegian State's participation was reorganised through the establishment of the SDFI. Through this reorganisation the Norwegian State began taking a direct financial interest in production licences. The establishment of the SDFI entailed a transfer of a substantial part of our participation in most of our then-existing licences to the SDFI, although formally such licences continued to be held wholly in our name. Since its establishment in 1985, the SDFI has taken shares in most licences awarded. The SDFI also holds shares in a number of oil and gas pipelines and land-based terminal facilities.

In connection with the restructuring, the Norwegian State established a new State-owned company, Petoro AS, in May 2001 which took over responsibility for, and the management of, the SDFI assets as licensee, in accordance with a new chapter of the Petroleum Act. The Norwegian State continues to be the beneficial owner of these assets. We continue to market and sell the Norwegian State's oil and gas together with our own oil and gas, pursuant to the owner's instruction described under report section 3.10.8 Operational review-Regulation-Marketing and sale of SDFI oil and gas. One of the tasks of Petoro AS is to supervise our compliance with the owner's instruction.

Petoro AS does not own any of the oil and gas produced under the licence interests it holds, does not receive any revenues from sales of the Norwegian State's oil and gas, and is not permitted to obtain an operator role. However, Petoro AS may become a participant in new licences awarded by the Norwegian State.

3.10.9 Gassco AS

Gassco AS - the gas transportation operating company

In connection with the restructuring of the Norwegian State's oil and gas interests in May 2001, the Norwegian State established a separate company, Gassco AS.

Gassco took over as operator of the natural gas transportation system previously operated by us on 1 January 2002. Gassco AS is wholly owned by the Norwegian State. The owners of the infrastructure systems appointed Gassco AS as the new operator.

The transfer of the operatorship to Gassco AS was made without consideration of, and does not affect existing arrangements, with respect to ownership or access to the natural gas transportation system or tariffs for transport. However, in accordance with the joint venture agreements relating to each of the gas transportation assets, the operator is entitled to be reimbursed for its costs as operator. Accordingly, since Gassco AS was appointed as operator, we no longer receive such reimbursement, and we will, as will other users of the infrastructure, be required to pay our portion of Gassco AS's expenses associated with the operation of the natural gas pipelines in which we hold interests.

Gassco AS has entered into contracts with us for each infrastructure joint venture, pursuant to which we will carry out technical operating activities on behalf of Gassco AS, such as system maintenance, for which we will receive reimbursement of costs. Either Gassco AS or we may terminate without cause each of these contracts, except the contract for the Statpipe joint venture, after five years. Either Gassco AS or we may also terminate the part of the Statpipe contract, which refers to the offshore pipelines, after five years. Currently, Gassco AS may terminate the part of the Statpipe contract that refers to the Kårstø plant, at any time, provided that 2/3 of the owners, representing more than 2/3 of the ownership interests, have supported such termination.

The natural gas transportation system was transferred to a new joint venture called Gassled as of 1 January 2003. Gassco AS is the operator of the Gassled joint venture. Our initial direct ownership interest in Gassled is currently 32.06% (32.86% including our indirect interest through our 28.58% holding in Norsea Gas AS), 15.71% in Zeepipe Terminal JV and 20.84% in Dunkerque Terminal DA. From 1 January 2011, our direct ownership interest in Gassled will be reduced to 28.05% due to an increased ownership interest for SDFI. In addition, our ownership interest in Gassled may also change as a result of inclusion of existing or new infrastructure or if Gassled undertakes further investments without participation from its owners in the same ratio as their ownership interests in Gassled. For more information on the Gassled joint venture, see report section 3.3.4 Operational review-Natural Gas-Norway's gas transportation system.

3.11 Competition

In the oil and gas industry there is intense competition for customers, production licences, operatorships, capital and experienced human resources.

In recent years the oil and gas industry has experienced consolidation, as well as increased deregulation and integration in strategic markets.

StatoilHydro competes with major integrated oil and gas companies, as well as independent and government-owned companies for the acquisition of assets and licences for the exploration, development and production of oil and gas, and for the refining, marketing and trading of crude oil, natural gas and related products. Key factors affecting competition in the oil and gas industry are oil and gas prices and demand, the cost of exploration and production, global production levels, alternative fuels and governmental and environmental regulations.

StatoilHydro's ability to remain competitive will require, among other things, management's continued focus on reducing unit costs and improving efficiency, maintaining long-term growth in our reserves and production through continued technological innovation and our ability to capture international opportunities in areas where our competitors may also be actively pursuing exploration and development opportunities. The company believes that it is in a position to compete effectively in each of its business segments.

3.12 Property, plant and equipment

We have interests in real estate in numerous countries throughout the world, but no one individual property is significant to us as a whole. Plans have been announced for a new office building to be leased in Oslo.

Our principal offices located at Forusbeen 50, N-4035, Stavanger, Norway, comprise approximately 135,000 square metres of office space, and are owned by StatoilHydro.

A letter of intent has been signed with IT Fornebu Holding AS in Oslo for the long-term lease of a new 60,000 square metre office building to be built at Fornebu in Bærum municipality. The building will enable all of StatoilHydro's activities in the Oslo region to be collocated, and will be ready for occupation in the autumn of 2012. IT Fornebu Holding AS will be the owner and StatoilHydro will be the tenant.

For a description of our significant reserves and sources of oil and natural gas, see note 34 - supplementary oil and gas information in the Consolidated Financial Statements. in this report.

3.13 Related party transactions

We have the following transactions with related parties, including state-owned entities and the bank DnB NOR:

Transactions with the Norwegian State
For a description of shares held by the Norwegian State, see report section 7.8 Shareholder information-Major shareholders. See also report section 4.2.3 Financial performance-Liquidity and capital resources-Material contracts for details on the merger between Statoil and Norsk Hydro's oil and energy activities.

Transactions with other entities in which the Norwegian State is a major shareholder
As a result of the substantial proportion of industry in Norway controlled by the Norwegian State, there are many state-controlled entities with whom we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State of such counter parties has not had any effect on the arm's-length nature of the transactions. In particular, in respect of the goods and services that we purchase, we purchase telephone services from Telenor ASA, a telecommunications company in which the Norwegian State holds a 53.97% interest. Such purchases are made pursuant to standard tariff rates applicable to public and private companies in Norway.

Other transactions with the Norwegian State
Total purchases of liquids and natural gas from the Norwegian State amounted to NOK 112,682 million (223 mmboe) in 2008, NOK 98,498 million (237 mmboe) in 2007 and NOK 104,628 million (254 mmboe) in 2006. Purchases of natural gas from the Norwegian State (excluding purchases from licences and sales on behalf of the Norwegian State) amounted to NOK 375 million in 2008, NOK 287 million in 2007 and NOK 293 million in 2006. The prices paid by StatoilHydro for the oil purchased from the Norwegian State are estimated market prices. In addition, StatoilHydro sells the Norwegian State's natural gas, in its own name, but for the account and risk of the Norwegian State.

The Norwegian State compensates us for its relative share of the costs related to certain StatoilHydro natural gas storage and terminal investments and related activities. See report section 3.10.8 Operational review-Regulation-Marketing and sale of the SDFI's oil and gas for more details.

Although StatoilHydro is majority-owned by the Norwegian State, it does not receive any preferential treatment with respect to licences granted by or under any other regulatory rules enforced by the Norwegian State.

Employee Loans
We have a general arrangement with DnB NOR whereby DnB NOR makes available to each of our employees personal consumer loans of up to NOK 300,000. The employees pay the "norm interest rate", which is variable and set by the Norwegian State, and we pay the difference between the norm interest rate and the then-current market interest rate. We also guarantee these loans up to an aggregate maximum amount of NOK 10 million. The repayment period is up to eight years. Our obligations for paying the interest rate difference will be dependent on the loan volume, but based on current interest rates would not exceed NOK 5 million per year.

Three employee-elected members of the board of directors and one member of the executive Committee each entered into loan agreements under this facility prior to 30 July 2002, and had, as of 31 December 2008, an aggregate total balance outstanding payable to DnB NOR under this loan facility of NOK 628,180. Members of the executive committee and the board of directors may not enter into loans under the foregoing programme.

Employees in certain employment levels are entitled to an interest free car loan from the company. Members of the executive committee and employee elected members of the board are generally excluded from this arrangement. As of 31 December 2008 none of the members of the executive committee had such loans, while one of the employee elected members of the board had a loan balance of NOK 260,555.

4 Financial performance

StatoilHydro delivered a strong operational performance in 2008 marked by record high equity production, the most expansive exploration programme ever and net operating income amounting to NOK 198.8 billion.

We also delivered significant synergies from the merger, and the ongoing integration and standardisation of offshore operations is aimed to further improve HSE results. These improvements will also increase StatoilHydro's flexibility and efficiency in the organisation.

With the addition of a strong balance sheet and active cost management, StatoilHydro is well positioned to manage through the global economic downturn. The group has the necessary strength and flexibility to pursue the long term strategic direction.

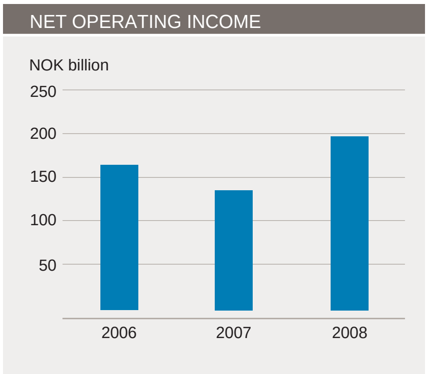
A downturn also represents an opportunity for improvements. We seek to reduce our own costs, improve quality and processes and work with our suppliers to bring industry costs down to more sustainable levels. The ongoing integration and standardisation of operational activities is a key element in our improvement agenda.

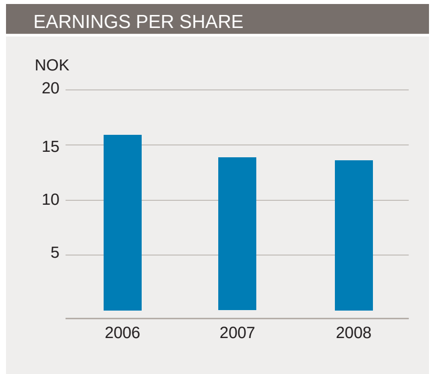
The following tables show selected consolidated financial and statistical data for StatoilHydro. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU). The accounting policies applied by the Group also comply with IFRSs as issued by the International Accounting Standards Board (IASB).

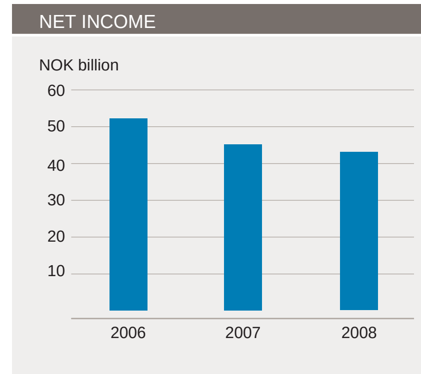
CONSOLIDATED STATEMENTS OF INCOME

(in NOK million)	For the year ended 31 December 2008	2007	2006
REVENUES AND OTHER INCOME			
Revenues	**652.0**	521.7	519.0
Net income (loss) from associated companies	**1.3**	0.6	0.7
Other income	**2.8**	0.5	1.8
Total revenues and other income	**656.0**	522.8	521.5
OPERATING EXPENSES			
Purchases [net of inventory variation]	**(329.2)**	(260.4)	(249.6)
Operating expenses	**(59.3)**	(60.3)	(44.8)
Selling, general and administrative expenses	**(11.0)**	(14.2)	(10.8)
Depreciation, amortisation and impairment losses	**(43.0)**	(39.4)	(39.5)
Exploration expenses	**(14.7)**	(11.3)	(10.7)
Total operating expenses	**(457.2)**	(385.6)	(355.3)
Net operating income	**198.8**	137.2	166.2
FINANCIAL ITEMS			
Net foreign exchange gains (losses)	**(32.6)**	10.0	4.5
Interest income and other financial items	**12.2**	2.3	3.7
Interest and other finance expenses	**2.0**	(2.7)	(3.1)
Net financial items	**(18.4)**	9.6	5.1
Income before tax	**180.5**	146.8	171.2
Income tax	**(137.2)**	(102.2)	(119.4)
Net income	**43.3**	44.6	51.8
Attributable to:			
Equity holders of the parent company	**38.3**	44.1	51.1
Minority interest	**5.0**	0.5	0.7
	43.3	44.6	51.8
Earnings per share for income attributable to equity holders of the company - basic and diluted	**13.58**	13.80	15.82

4.1 Strong operational performance







Good operational performance is the best protection in times of uncertainty, and the merger was key to our continuous performance improvements. We delivered record production in 2008 and brought 12 new fields on stream.

In 2008, StatoilHydro delivered total liquids and gas entitlement production of 1.751 mboe per day, up 2% from 1.724 mboe per day in 2007. The contribution from international operations reached a record high and accounted for 18% of entitlement production. Total equity production increased by 5% from 2007 to 1.925 mboe per day in 2008. Strong production and high prices contributed to a net operating income of NOK 198.8 billion in 2008, compared to NOK 137.2 billion in 2007. The increase was mainly due to an increase in realised prices on both liquids and natural gas, measured in NOK, and was only partly offset by increased operating expenses caused by a higher activity level and new, more expensive fields coming on stream.

StatoilHydro delivered an extensive exploration programme in 2008. Of a total of 79 exploration wells completed before 31 December 2008, 40 were drilled outside the NCS. Thirty-five wells were declared as discoveries, of which eight are located outside the NCS. An additional eight wells have been completed since 31 December 2008. In 2008, 230 mmboe were added through revisions, extensions and discoveries. In total, the company achieved a reserve replacement ratio of 34% in 2008.

StatoilHydro maintained a high level of activity in progressing projects into production in 2008. Seven projects on the NCS and six international projects came on stream in 2008, and we also sanctioned 13 new projects for development, of which four are outside Norway.

During 2008, the group gained access to 20 new exploration licences in the Gulf of Mexico, Alaska, Brazil, Canada and the Faroe Islands. On the NCS we were granted access to 12 new licences, as operator in nine and as partner in three. In addition the group acquired a 15% interest in the Goliat field and a 10% interest in the Ragnarrock discovery on the NCS. In accordance with an agreement with Chesapeake Energy Corporation, StatoilHydro acquired a 32.5% interest in the Marcellus shale gas acreage in the USA. Statoilhydro also completed the purchase of the remaining 50% interest and became the operator of the Peregrino development offshore Brazil.

The report for 2007 was the first annual report in which financial statements for the merged StatoilHydro organisation was presented. Historical data was restated as if the merged company had existed for all periods.

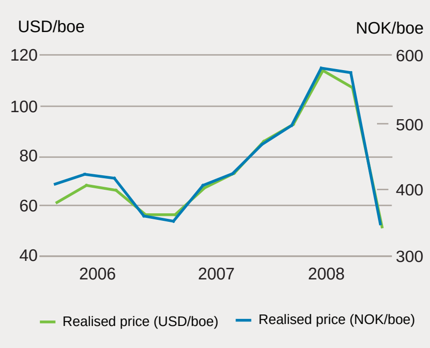
4.1.1 Group profit and loss analysis

Revenues and other income were NOK 133.2 billion higher than in 2007 and 134.5 million more than in 2006. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by StatoilHydro.

Consolidated statements of income (in NOK billion)	2008	Twelve months ended 31 December 2007	08 -07 Change	2006	07-06 Change
Revenues and other income					
Revenues	**652.0**	521.7	25%	519.0	1%
Net income (loss) from equity accounted investments	**1.3**	0.6	111%	0.7	10%)
Other income	**2.8**	0.5	428%	1.8	(72%)
Total revenues and other income	**656.0**	522.8	25%	521.5	0%
Operating expenses					
Purchase, net of inventory variation	**329.2**	260.4	26%	249.6	4%
Operating expenses	**59.3**	60.3	(2%)	44.8	35%
Selling, general and administrative expenses	**11.0**	14.2	(23%)	10.8	31%
Depreciation, amortisation and impairment	**43.0**	39.4	9%	39.5	(0%)
Exploration expenses	**14.7**	11.3	30%	10.7	6%
Total operating expenses	**457.2**	385.6	19%	355.3	9%
Net operating income	**198.8**	137.2	45%	166.2	(17%)
Net financial items	**(18.4)**	9.6	(291%)	5.1	89%
Income tax	**(137.2)**	(102.2)	(34%)	(119.4)	14%
Net income	**43.3**	44.6	(3%)	51.8	(14%)
Earnings per share for income attributable to equity holders of company basic and diluted	**13.6**	13.8	(100%)	15.8	(13%)

Operational data	2008	2007	08-07 Change	2 006	07-06 Change
	Twelve months ended 31 December				
Average liquids price (USD/bbl)	**91.0**	70.5	29%	63.2	12%
USDNOK average daily exchange rate	**5.63**	5.86	(4%)	6.42	(9%)
Average liquids price (NOK/bbl) [3]	**513**	413	24%	406	2%
Gas prices (NOK/scm)	**2.40**	1.66	45%	1.94	(15%)
Refining margin, FCC (USD/boe) [4]	**8.2**	7.5	9%	7.1	6%
Total entitlement liquids production (mboe per day)[5]	**1,055**	1,070	(1%)	1,057	1%
Total entitlement gas production (mboe per day)	**696**	654	6%	651	0%
Total entitlement liquids and gas production (mboe per day) [6]	**1,751**	1,724	2%	1,708	1%
Total equity liquids production (mboe per day)	**1,200**	1,165	3%	1,118	4%
Total equity gas prodcution (mboe per day)	**725**	674	8%	661	2%
Total equity liquids and gas production (mboe per day)	**1,925**	1,839	5%	1,780	3%
Total liquids liftings (mboe per day)	**1,019**	1,081	(6%)	1,048	3%
Total gas liftings (mboe per day)	**696**	654	6%	651	0%
Total liquids and gas liftings (mboe per day) [7]	**1,714**	1,735	(1%)	1,699	2%
Production cost entitlement volumes (NOK/boe, last 12 months) [8]	**38.1**	44.1	(14 %)	28.4	55 %
Equity production cost excluding restructuring and gas injection cost (NOK/boe, last 12 months) [10]	**33,3**	31.2	7 %	28,1	11%

GROUP REALISED OIL PRICE

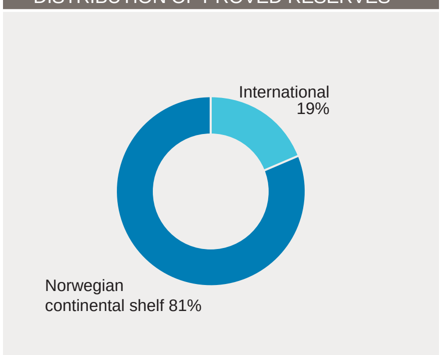


Revenues and other income totalled NOK 656.0 billion in 2008. This was NOK 133.2 billion more than in 2007 and NOK 134.5 billion more than in 2006. Most of the **revenues** stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by StatoilHydro. We also market and sell the Norwegian State's share of oil from the NCS. All purchases and sales of the Norwegian State's production are recorded as purchases net of inventory variations and sales, respectively.

Realised prices of liquids measured in NOK increased by 29% from 2007 to 2008. The increased prices of liquids contributed NOK 37.0 billion to the revenues, whereas the overall gas sales contributed NOK 6.1 billion and the increase in prices of natural gas contributed NOK 29.2 billion to the change. This was partly off-set by a decrease in liftings of liquids of NOK 9.0 billion.

Realised oil prices measured in NOK increased by 2% from 2006 to 2007. The increased oil prices contributed NOK 3.1 billion to the revenues, whereas the contribution from increased oil liftings was NOK 5.0 billion. Overall gas sales contributed with NOK 3.6 billion to the change. This was partly off-set by a decrease in gas prices with a negative impact of NOK 10.4 billion.

DISTRIBUTION OF PROVED RESERVES



The volumes of liquids lifted should over time correlate with the volumes produced. However, the volumes may be higher or lower than production in any period due to operational factors affecting the timing of when we lift the liquids from the fields. **Total liquids liftings** decreased from 1.081 mmboe per day in 2007 to 1.019 mmboe per day in 2008. From 2006 to 2007, total liquids liftings increased from 1.048 mmboe per day in 2006 to 1.081 mmboe per day in 2007.

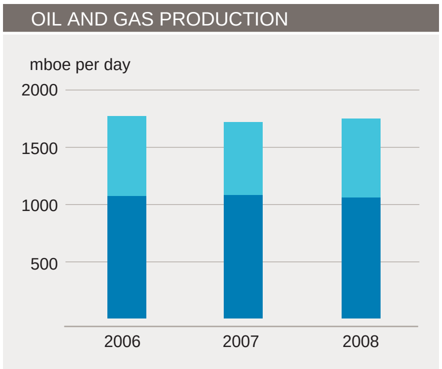
Entitlement volumes lifted is the basis for the revenue recognition while equity production volumes more directly affect operating costs. See report section 4.1.9 Financial performance-Strong operational performance-Reported volumes for more details on the PSA effects that cause differences between equity and entitlement volumes. See below for more details on the difference between lifted and produced volumes.

Total natural gas sales were 45.2 bcm (1,60 tcf) in 2008, 42.0 bcm (1.48 tcf) in 2007 and 40.2 bcm (1.42 tcf) in 2006. The 8% increase from 2007 to 2008 was mainly due to increased entitlement gas sales, but was partly offset by a net decrease in StatoilHydro third party sales volumes. The increase in entitlement sales volumes mainly relates to higher production from NCS in addition to the first full year of production from Shah Deniz in Azerbaijan. From 2006 to 2007, the increase of 1.8 bcm was mainly due to higher third party gas sales, and was partly offset by a net decrease in StatoilHydro entitlement sales volumes.

Net income (loss) from equity accounted investments. Our share of equity in net income of affiliates was NOK 1.3 billion in 2008, NOK 0.6 billion in 2007 and NOK 0.7 billion in 2006.

Other income was NOK 2.8 billion in 2008 compared to NOK 0.5 billion in 2007 and NOK 1.8 billion in 2006. The income in 2008 and 2007 was mainly related to gain from sale of assets whereas the income in 2006 was mainly related to a change in the write-down of inventory to production cost and gains from sales of assets.

OIL AND GAS PRODUCTION



Purchase, net of inventory variation includes the cost of the oil and NGL production that we purchase from the Norwegian State pursuant to the Marketing Instruction. The purchase, net of inventory variation amounted to NOK 329.2 billion in 2008 compared to NOK 260.4 billion in 2007 and NOK 249.6 billion in 2006. The increase from 2006 throughout 2008 was mainly caused by higher prices of liquids measured in NOK.

***Operating* expenses** include field production costs and transport systems related to the company's share of oil and natural gas production. Operating expenses were NOK 59.3 billion in 2008 compared to NOK 60.3 billion in 2007 and NOK 44.8 billion in 2006. The 2% decrease from 2007 to 2008 was primarily due to restructuring costs related to the merger in 2007 and was only partly offset by increased costs related to start-up of new fields, higher activity and industry cost inflation in 2008. The 35% increase from 2006 to 2007 was primarily due to restructuring costs and other costs related to the merger, as well as higher operation and maintenance costs, increased transportation costs and new fields coming on stream.

Total liquids and gas production increased from 1.724 mmboe per day in 2007 to 1.751 mmboe per day in 2008. In 2006, total liquids and gas production was 1.708 mmboe per day. Equity production of oil and gas increased from 1.839 mmboe per day in 2007 to 1.925 mmboe per day in 2008. In 2006, equity production of liquids and gas was 1.780 mmboe per day.

Production cost per boe was NOK 38.1 for the 12 months ended 31 December 2008, compared to NOK 44.1 for the 12 months ending 31 December 2007. [8] In 2006, production cost per boe was NOK 28.4 (USD 4.44).

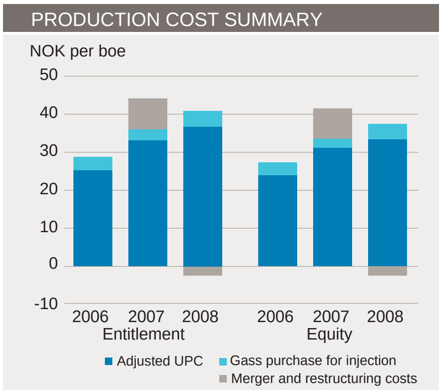
Based on equity volumes, [10] the production cost per boe for the two periods was NOK 33.5 and NOK 41.4, respectively. Normalised at a USDNOK exchange rate of 6.00, the production cost for the 12 months ending 31 December 2008 was NOK 38.6 per boe, compared to NOK 44.3 per boe for the 12 months ending 31 December 2007 and NOK 28.1 per boe for the 12 months ending 31 December 2006 [9]. Normalised production cost is defined as a non-GAAP financial measure. [2]

The production cost per boe, both actual and normalised, has decreased significantly from 2007 to 2008, mainly due to a NOK 3,6 billion change in non-recurring restructuring costs relating to the merger in 2007, but the positive effect was partly offset by start-up of new fields, increased maintenance cost and general industry cost pressure.

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 of equity production for the 12 months ending 31 December 2008 and 2007, was NOK 33.3 and NOK 31.2 respectively.

These figures have not been normalised for currency effects. Adjustments are made for certain costs related to the purchase of gas used for injection into oil-producing reservoirs. The adjustment facilitates comparison of field production costs with other fields which do not pay for their own gas used for injection into oil producing reservoirs.

PRODUCTION COST SUMMARY



Selling, general and administrative expenses include expenses related to the sale and marketing of our products, such as business development costs, payroll and employee benefits. These amount to NOK 11.0 billion in 2008, compared with NOK 14.2 billion in 2007 and NOK 10.8 billion in 2006. The 23% decrease from 2007 to 2008 was mainly due to restructuring costs related to the merger in 2007 and was only partly offset by increased costs related to higher activity and industry cost inflation in 2008. The 32% increase from 2006 to 2007 was also mainly due to restructuring costs and other costs arising from the merger in 2007, and was only partly offset by a pre-tax gain in 2006 of NOK 0.6 billion from the sale of Statoil Ireland.

Depreciation, amortisation and impairment 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. These expenses amounted to NOK 43.0 billion in 2008, compared to NOK 39.4 billion in 2007 and NOK 39.5 in 2006.

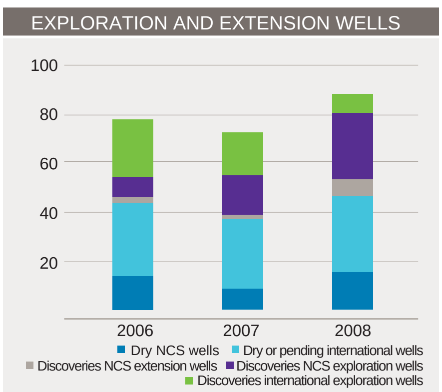
The 9% increase in depreciation, amortisation and impairment expenses in 2008 compared to 2007 was due to impairment charges net of reversals of NOK 2.3 billion, mostly related to GoM, and an increase in production.

Depreciation, amortisation and impairment expenses in 2007 showed a decrease of NOK 3.3 billion compared to 2006. The decrease was offset by higher asset retirement costs of NOK 2.1 billion and the start-up of new fields in 2007. The impairments of Gulf of Mexico shelf fields and Front Runner amounted to NOK 4.9 billion in 2006, compared to impairments in 2007 of Lufeng, Front Runner, Thunder Hawk and GoM shelf fields amounting to NOK 1.2 billion.

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 2008 and write-offs of exploration expenditure capitalised in previous years. The exploration expense was NOK 14.7 billion in 2008, NOK 11.3 billion in 2007 and NOK 10.7 billion in 2006.

Exploration (in NOK billion)	2008	2007	For the year ended 31 December 08-07 change	2006	07-06 change
Exploration expenditure (activity)	**17.8**	14.2	25%	13.4	6%
Expensed, previously capitalised exploration expenditure	**3.7**	1.7	183%	1.5	13%
Capitalised share of current periods exploration activity	**(6.8)**	(4.6)	48%	(4.2)	10%
Exploration expense	**14.7**	11.3	30%	10.7	6%

The 30% increase in exploration expenses from 2007 to 2008 was mainly due to a higher number of wells drilled, generally more expensive wells, higher field evaluation costs and delineation on the oilsands project in Canada. The 6% increase in exploration expenses from 2006 to 2007 was mainly due to higher exploration activity, generally more expensive wells and an increase in the expensing of previously capitalised licences and well expenditures.



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 have been declared as discoveries. In 2007, a total of 71 exploration and appraisal wells and two exploration extension wells were completed, 26 on the NCS and 47 internationally. Thirty-four exploration and appraisal wells and two exploration extension wells were declared as discoveries.

In 2007, a total of 71 exploration and appraisal wells were completed, 24 on the NCS and 47 internationally. In addition, two exploration extension wells were completed in the same period. Thirty-four of the exploration and appraisal wells were confirmed discoveries, 16 on the NCS and 18 internationally. Both exploration extension wells were discoveries.

In 2006, a total of 73 exploration and appraisal wells were completed, 18 on the NCS and 55 internationally. Five exploration extension wells were completed during the same period. Thirty-two of the exploration and appraisal wells were confirmed discoveries, eight on the NCS and 24 internationally. Two exploration extension wells were discoveries.

Net operating income was NOK 198.8 billion in 2008, compared to NOK 137.2 billion in 2007 and NOK 166.2 billion in 2006. The 45% increase from 2007 to 2008 was mainly due to higher realised prices on both liquids and natural gas, measured in NOK, and was only partly offset by increased operating expenses caused by a higher activity level and new, more expensive fields coming on stream.

The 18% decrease in net operating income from 2006 to 2007 was mainly due to an increase in operating, selling and administrative expenses stemming in part from restructuring and other costs arising from the merger, a negative change in derivatives, new fields coming on stream and increased activity levels. The restructuring costs and other costs arising from the merger were recorded primarily under operating and general and administrative expenses, and were allocated to the business areas where possible. Restructuring costs and other costs arising from the merger was primarily related to pensions and early retirement costs and impairment of assets in Sweden.

In 2008, net operating income was impacted of 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 impacted 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 impacted net operating income in 2008.

In 2007, net operating income was impacted of the following items: impairment charges net of reversals (NOK 2.8 billion), loss on derivatives to hedge the value of inventories (NOK 1.1 billion), other accruals (NOK 1.2 billion), restructuring cost accrual (NOK 6.7 billion) and other costs related to the merger (NOK 3.2 billion) all impacted net operating income in 2007 negatively, while increased fair value of derivatives (NOK 0.5 billion), overlift (NOK 1.6 billion), higher values of products in operational storage (NOK 1.5 billion) positively impacted net operating income in 2008.

In 2008, **Net financial items** amounted to a loss of NOK 18.4 billion, compared to a gain of NOK 9.6 billion in 2007.

The NOK 28.0 billion negative change from 2007 to 2008 was mostly attributable to NOK 32.6 billion in currency losses caused by a 29% weakening of NOK against USD in 2008 compared to a NOK 10.0 billion gain from a 14% strengthening of the NOK against the USD in 2007. The negative impact of currency exchange losses was partly offset by a NOK 9.9 billion increase in interest income and other financial items and a NOK 4.7 billion decrease in interest and other financial expenses.

Interest income and other financial items amounted to NOK 12.2 billion in 2008, compared to NOK 2.3 billion in 2007. The increase of NOK 9.9 billion mainly related to an increase in interest income of NOK 4.4 billion and an increase in income from securities of NOK 5.5 billion, mainly related to currency gains on USD denominated investments.

Interest and other financial expenses amounted to a net gain of NOK 2.0 billion in 2008, compared to a net loss of NOK 2.7 billion in 2007. The decrease of NOK 4.7 billion mainly related to a NOK 5.1 billion change in fair value adjustment of interest rate swap positions used to manage the interest rate risk on the external loan portfolio, due to a decrease in USD rates of 2.2% during 2008.

In 2007 net financial items amounted to an income of NOK 9.6 billion, compared to an income of NOK 5.1 billion in 2006. The 88% increase was principally the result of changes in currency gains and losses on the USD portions of our non-current financial liabilities outstanding and currency gains and losses on NOK hedging transactions. In both cases, currency gains and losses relate to changes in the USDNOK exchange rate, due to the weakening of the USD against the NOK.

Currency swaps are used for risk management purposes to hedge our long-term interest-bearing loans recorded in USD. As a result, the company's long-term debt portfolio is exposed to changes in the USDNOK exchange rate. The USD weakened by NOK 0.85 in relation to the NOK in 2007, compared to a weakening of NOK 0.51 in 2006.

Interest and other financial income amounted to NOK 2.3 billion in 2007, compared to NOK 3.7 billion in 2006. Interest and other financial expenses amounted to NOK 2.7 billion in 2007, compared to NOK 3.1 billion in 2006. The decrease in interest and other expenses was mainly due to a decrease in interest expenses on our long term loan portfolio, caused by currency effects and gains on interest rate swaps related to former Hydro long-term interest-bearing loan contracts. This portfolio was swapped from fixed to floating interest rate in the second half of 2007. These effects were partly offset by increased accretion expenses related to asset retirement obligations and a decrease in interest being capitalised. This was mainly due to the fact that fields such as Snøhvit and Ormen Lange came on stream in 2007.

Management of the portfolio of security investments, mainly related to equity securities, is held by our insurance captive, Statoil Forsikring AS, commercial papers is held by Statholding AS and liquidity funds is held by StatoilHydro ASA.

The Norwegian central bank's closing rate for USDNOK was 7.00 on 31 December 2008, 5.41 on 31 December 2007 and 6.26 on 31 December 2006. These exchange rates have been applied in StatoilHydro's financial statements.

In 2008 **income taxes** were NOK 137.2 billion, equivalent to a tax rate of 76.0%, compared to NOK 102.2 billion equivalent to a tax rate of 69.6% in 2007.

The increase in the tax rate in 2008 was mainly related to the net loss on financial items which is tax deductible at a lower tax rate than the average rate. In addition, the tax rate was increased by the deferred tax expense caused by currency effects in certain group companies which are taxable in a different currency than the functional currency. This was partly offset by the tax effect of a proportionally higher operating income being subject to a lower than average tax rate.

The effective tax rate is calculated as income taxes divided by income before taxes. Fluctuations in the effective tax rates from year to year are principally the result of non-taxable items (permanent differences), changes in the components of income between Norwegian oil and gas production, taxed at a marginal rate of 78%; other Norwegian income, including the onshore portion of net financial items taxed at 28%, and income in other countries taxed at the applicable income tax rates.

Adjusted for the non-recurring NOK 2.0 billion reduction in deferred tax liabilities relating to allocation of financial items with respect to the NCS and temporary differences in inter-company transactions, income taxes in 2006 were NOK 119.4 billion, equivalent to a tax rate of 69.7%. The tax rate in 2007 was lower than the adjusted tax rate in 2006, mainly due to higher net financial income and the increased effect of uplift deduction on the NCS. The lower tax rate was partly offset by relatively less income from outside the NCS being subject to lower taxation than the average tax rate.

In 2008, the **Minority interest** in net profit was NOK 0.005 billion, compared to NOK 0.5 billion in 2007. The minority interest is primarily related to the Mongstad crude oil refinery. In 2006, the minority interest in net profit was NOK 0.7 billion in 2006.

Net income was NOK 43.3 billion in 2008, compared to NOK 44.6 billion in 2007. The decrease was mainly due to a loss on financial items, high income taxes and increased operating expenses, and was only partly offset by higher prices on both liquids and natural gas, measured in NOK. In 2006, net income was NOK 51.9 billion and the decrease in 2007 was mainly due to lower operating income primarily because of restructuring costs and other costs arising from the merger, negative changes in derivatives and a higher tax rate, partly offset by higher net financial income.

The Board of Directors proposes an ordinary **dividend** of NOK 4.40 per share for 2008 to the Annual General Meeting, as well as NOK 2.85 per share in special dividend, making an aggregate total of NOK 23.1 billion. Ordinary dividend for 2007 was NOK 4.20 per share, as well as NOK 4.30 per share in special dividend, making an aggregate total of NOK 27.1 billion in 2007. In 2006, ordinary and special dividend was NOK 4.00 per share and NOK 5.12 per share, respectively, making an aggregate total of NOK 19.7 billion.

4.1.2 Group outlook

StatoilHydro expects entitlement production to remain at approximately 2008 levels in 2009. This assumes no adverse effects of potential reductions in OPEC quotas.

Maintenance activity is expected to have little impact on the equity production in the first quarter of 2009.

Capital expenditures for 2009, excluding acquisitions, are estimated to be around USD 13.5 billion. Approximately 50% of the forecasted investments for 2009 are in assets expected to contribute to growth in oil and gas production, about one third are related to investments in currently producing assets, with the remainder in other activities.

Unit production cost for equity volumes is estimated in the range of NOK 33 to 36 per barrel in the period from 2009 to 2012, excluding purchases of fuel and gas for injection. For 2009, the unit production cost is expected to be temporarily in the upper end of this range. The short term increase is expected to be caused by several large fields ramping up or preparing for production. In addition, some fields, such as ACG and Kvitebjørn, are not producing at full capacity. Furthermore, a high degree of maintenance during 2009 and continuing uncertainty regarding developments in the NOK/US dollar rate are expected to adversely affect the unit production cost in 2009.

StatoilHydro's ambition is to deliver a competitive **ROACE** compared with its peer group.

Exploration drilling is the primary tool for growing our business. We will continue to high-grade our large portfolio of exploration assets and we expect to maintain a high level of **exploration activity** in 2009, although slightly lower than in 2008. We expect to complete between 65 and 70 exploration and appraisal wells in 2009. Rigs have already been secured for most of the exploration drilling in 2009 and to some extent also for subsequent years. Exploration activity is estimated to amount to some USD 2.7 billion for 2009.

The year 2008 was one of the most **volatile periods in the product, gas liquid and crude oil markets**. While natural gas prices have been strong in Europe, crude oil and gas liquids prices decreased dramatically during the third and fourth quarters of 2008. We anticipate that crude oil and gas liquids prices will remain at relatively low levels and that prices will continue to be volatile at least in the near term.

The price development for natural gas is uncertain in the short term due to the financial turmoil. The natural gas market is also influenced by developments in the overall power market and the industrial segment in which gas competes with coal and fuel oil products, both having fallen significantly in price. Going forward, the value of natural gas in the power segment will increasingly be determined by competition with coal, renewable energy and nuclear energy. Climate policies and regulations will also be important factors in determining gas pricing.

New LNG capacity is coming on stream, and will be directed to the most favourable markets. As the amount of available LNG is anticipated to be substantial, there is a corresponding uncertainty related to the price effects to the relevant markets.

In the long term, we continue to have a 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 Cove Point will provide a foundation for growth in our US market position in the years to come.

StatoilHydro'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. See section 10 Forward looking statements.

4.1.3 Segment performance and analysis

Oil and natural gas are subject to internal transactions between our business segments before being sold in the market. We have established a pricing policy for transfers based on the market price.

The table details certain financial information for our four business segments: Exploration and Production Norway (EPN), International Exploration and Production (INT), Natural Gas (NG) and Manufacturing and Marketing (M&M). When combining business segment results, we eliminate intercompany sales. These include transactions recorded in connection with our oil and natural gas production in the EPN or INT segments, and also in connection with the sale, transport or refining of our oil and natural gas production in the M&M or NG segments.

EPN produces oil, which it sells internally to Oil Sales, Trading and Supply (OTS) in the M&M segment, which then sells the oil in the market. EPN also produces natural gas, which it sells internally to our NG segment, also for sale in the market. A large share of the oil and a small share of the natural gas produced by INT is also sold in the same way as the oil and the natural gas produced by EPN. The remaining oil and gas from INT is sold directly in the market. We have established a market price-based transfer pricing policy whereby we set an internal price at which our EPN business area sells oil and natural gas to the M&M and NG segments.

The transfer price formula for natural gas produced by EPN and marketed and sold by NG was changed as of 1 January 2008 in order to to better reflect fundamental changes in the markets for competing energies, for instance crude oil, for developments in natural gas markets and for changes in the natural gas sales contracts portfolio. The new internal price is linked to the gas market prices and it also better reflects the distribution of value creation between NG and EPN. In 2008 the transfer price was NOK 1.87 per scm. The change was effective as of 1 January 2008 and is reflected in our financial reporting, without restating prior periods. The average transfer price for natural gas per standard cubic metre was NOK 1.87 in 2008, NOK 1.39 in 2007 and NOK 1.36 in 2006. For sales of oil from EPN to M&M, the transfer price of oil is the applicable market reflective price minus a margin of NOK 0.70 per barrel.

For additional information please refer to section 9.15 Segments in Notes to the Consolidated Financial Statements.

The table shows certain financial information for our four segments, including intercompany eliminations for each of the years in the three-year period ending 31 December 2008.

	For the year ended 31 December		
(in NOK billion)	**2008**	**2007**	**2006**
Exploration & Production Norway			
Total revenues	**219.8**	179.2	179.2
Net operating income	**166.9**	123.2	135.1
Non-current assets	**165.5**	153.1	151.5
International Exploration & Production			
Total revenues	**46.1**	41.6	32.6
Net operating income	**12.8**	12.2	3.9
Non-current assets	**160.6**	107.3	96.0
Natural Gas			
Total revenues	**110.8**	73.4	97.1
Net operating income	**12.5**	1.6	21.7
Non-current assets	**35.7**	35.6	30.1
Manufacturing & Marketing			
Total revenues	**531.3**	428.0	412.0
Net operating income	**4.5**	3.8	7.3
Non-current assets	**34.4**	27.6	25.2
Other and elimination			
Total revenues	**(252.1)**	(199.5)	(199.4)
Net operating income	**2.1**	(3.4)	(1.9)
Non-current assets	**3.9**	2.9	2.9
StatoilHydro group			
Total revenues	**656.0**	522.8	521.5
Net operating income	**198.8**	137.2	166.2
Non-current assets	**400.1**	326.5	305.6
Non-current assets, not allocated to segments	**33.5**	26.9	27.0

Sales by region (in NOK billion)	2008	% of total sales	For the year ended 31 December 2007	% of total sales	2006	% of total sales
Norway	**495.3**	**76%**	386.7	74%	393.3	76%
United States	**57.9**	**9%**	53.1	10%	45.6	9%
Sweden	**26.0**	**4%**	23.1	4%	21.7	4%
Denmark	**19.4**	**3%**	14.9	3%	14.6	3%
Singapore	**13.1**	**2%**	14.2	3%	8.6	2%
UK	**15.7**	**2%**	-	-	-	-
Other	**27.3**	**4%**	30.1	6%	36.9	7%
Total	**654.7**	**100%**	522.2	100%	520.8	100%

4.1.4 Exploration and Production Norway

Our overall strategy on the NCS is to conduct safe, efficient and reliable operations and capture the full potential of the NCS by developing profitable oil and gas resources.

StatoilHydro has delivered an extensive exploration programme on the NCS in 2008. We participated in 39 exploration and appraisal wells, of which 27 resulted in discoveries. In addition, we completed nine exploration extensions, of which six resulted in discoveries. Total exploration expenditure was NOK 8.7 billion in 2008, compared with NOK 5.7 billion in 2007 and NOK 4.6 billion in 2006.

The total capital expenditure in 2008 was NOK 34.9 billion compared with NOK 31.1 billion in 2007 and NOK 29.2 million in 2006. Around half of our investments are related to new fields, while the other half are investments on existing fields.

In total, seven new fields came on stream on the NCS in 2008: Volve, Gulltopp, Gamma Main Statfjord, Vigdis Øst, Theta Cook, Oseberg Delta and Vilje.

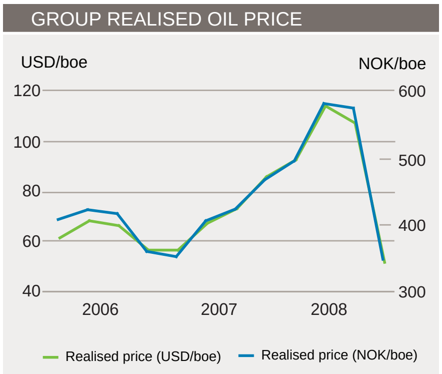
Our production of oil and gas on the NCS averaged 1.461 mmboe per day in 2008, compared to 1.417 mmboe per day in 2007 and 1.474 in 2006.

4.1.4.1 Profit and loss analysis

Exploration and Production Norway generated total revenues of NOK 219.8 billion in 2008 and net operating income was NOK 166.9 billion. The average daily entitlement production in 2008 was 824 mbbl per day for oil and 637 mboe per day for gas.

	Twelve months ended 31 December				
Income statement (in NOK billion)	2008	2007	08 -07 Change	2006	07-06 Change
Total revenues and other income	**219.8**	179.2	23%	179.2	0%
Operating expenses	**23.5**	29.1	(19%)	19.2	52%
Selling, general and administrative expenses	**(0.1)**	0.3	(135%)	0.5	(30%)
Depreciation, amortisation and impairment	**24.0**	23.0	4%	20.9	10%
Exploration expenses	**5.5**	3.6	52%	3.5	5%
Total expenses	**52.9**	56.1	(6%)	44.1	27%
Net operating income	**166.9**	123.1	36%	31.5	291%
Operational data:					
Liquids price (USD/bbl)	**91.5**	70.9	29%	63.6	11%
Liquids price (NOK/bbl)	**515.4**	415.2	24%	408.3	2%
Transfer price natural gas (NOK/scm)	**1.9**	1.4	34%	1.4	3%
Liftings:					
Liquids (mboe per day)	**807.8**	831.1	(3%)	856.0	(3%)
Natural gas (mboe per day)	**637.0**	598.6	6%	610.0	(2%)
Total liquids and gas liftings (mboe per day)	**1,444.7**	1,429.8	1%	1,466.0	(2%)
Production:					
Entitlement liquids (mboe per day)	**823.8**	817.9	1%	864.0	(5%)
Entitlement natural gas (mboe per day)	**636.9**	598.7	6%	610.0	(2%)
Total entitlement liquids and gas production (mboe per day)	**1,460.7**	1,416.5	3%	1,474.0	(4%)

GROUP REALISED OIL PRICE

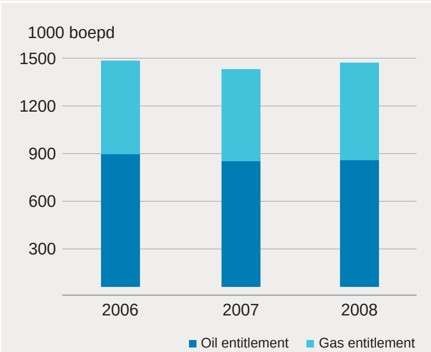


We generated **total revenues**of NOK 219.8 billion in 2008 and NOK 179.2 billion in 2007 and 2006. An increase of 31% in the average oil price in USD of oil sold by E&P Norway to Manufacturing and Marketing contributed NOK 54.6 billion, and a 35% increase in the average transfer price in NOK of natural gas sold by E&P Norway to Natural Gas, contributed NOK 17.9 billion. Lifted volumes of natural gas increased by 6.7%, making a positive contribution of NOK 3.2 billion. This was offset by a negative currency exchange rate deviation of NOK 11.1 billion due to a 7.2% decrease in the USD/NOK exchange rate. In addition, other income increased by NOK 3.1 billion, mainly as a result of a change in the fair value of derivatives. Lifted volumes of crude oil decreased by 2.5%, making a negative contribution of NOK 3.1 billion.

From 2006 to 2007 there was an increase of 11% in the average oil price in USD of oil sold by E&P Norway to Manufacturing and Marketing contributed NOK 13.3 billion, and a 2% increase in the average transfer price in NOK of natural gas sold by E&P Norway to Natural Gas, contributed NOK 1.1 billion. This was offset by a negative currency exchange rate deviation of NOK 12.0 billion due to a 9% decrease in the USD/NOK exchange rate. Lifted volumes of crude oil decreased by 3%, making a negative contribution of NOK 3.8 billion, and there was a 2% decrease in lifted volumes of natural gas, making a negative contribution of NOK 0.9 billion. In addition, other income increased by NOK 2.4 billion, mainly as a result of higher income from derivatives and higher processing income.

The average daily lifting of oil in 2008 was 808 mbbl per day, compared to 831 mbbl per day in 2007 and 856 mbbl per day in 2006.

PRODUCTION



Average daily entitlement oil production in 2008 was 824 mbbl per day, compared to 818 mbbl per day in 2007 and 864 mbbl per day in 2006. The increased production from 2007 to 2008 was mainly related to start-up of the Volve field in February 2008, higher production at Kvitebjørn until the shutdown from August 2008 compared to 2007 when Kvitebjørn was shut down to allow safe drilling operations most of the year, new wells at Fram and building up production at Ormen Lange. The increase was partly offset by declining production from wells in the Grane, Norne, Troll Olje, Tordis, Visund and Sleipner fields.

The reduced production from 2006 to 2007 was largely caused by the shutdown of production on the Kvitebjørn field from 1 May 2007 in order to allow drilling operations to be carried out safely, as well as a natural decline on the Oseberg field. The reduction in production was partly offset by increased production from the Kristin field, which reached plateau level in late 2007.

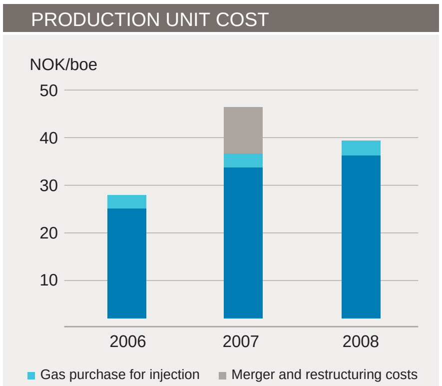
The average daily entitlement gas production was 637 mboe per day in 2008 (equal to 101.3 mmcm or 3.58 mmcf), compared to 599 mboe in 2007 (equal to 95.2 mmcm or 3.36 mmcf) and 610 mboe in 2006 (equal to 97.0 mmcm or 3.42 mmcf).

Operating, general and administrative expenses were NOK 23.4 billion in 2008. Operating, general and administrative expenses were NOK 29.4 billion in 2007 and NOK 19.6 billion in 2006. Operating costs amounted to NOK 23.5 billion in 2008. Operating costs amounted to NOK 29.1 billion in 2007 and NOK 19.2 billion in 2006.

The decrease of NOK 6.0 billion in operating, general and administrative expenses from 2007 to 2008 was mainly due to a decrease in other expenses of NOK 6.8 billion, mainly due to restructuring costs as a result of the merger in 2007 and a decrease in transportation costs by NOK 1.3 billion in 2008 due to increased elimination and reduced booking. In addition, selling, general & administrative expenses decreased by NOK 0.4 billion and processing costs decreased by NOK 0.3 billion, from 2007 to 2008. This was partially countered by an increase of NOK 2.7 billion in operating plant costs, which was largely due to start up of new fields of NOK 1.1 billion, increased cost for gas purchased for injection at Grane by NOK 0.5 billion and increased operational activity.

The increase of NOK 9.8 billion in operating, general and administrative expenses from 2006 to 2007 was mainly due to an increase in other expenses of NOK 6.3 billion, mainly due to restructuring costs as a result of the merger in 2007 and an increase of NOK 3.2 billion in operating plant costs, which was largely due to an increase in well maintenance costs of NOK 0.9 billion, higher operation and maintenance costs of NOK 0.8 billion, higher production fees, mainly due to the introduction of nitrogen oxide charges of NOK 0.4 billion in 2007, Grane Gas purchases totalling NOK 0.3 billion, higher business development costs of NOK 0.3 billion and higher head office research and development costs of NOK 0.2 billion. In addition, processing costs increased by NOK 0.4 billion from 2006 to 2007.

PRODUCTION UNIT COST



The unit production cost was NOK 37.31 per BOE in 2008 compared with NOK 46.26 per boe in 2007 and NOK 26.93 per boe in 2006. The total production cost was NOK 19.9 billion in 2008, compared with NOK 23.9 billion in 2007 and NOK 14.5 billion in 2006.

The 19% decrease from 2007 to 2008 is due to a decrease in costs of 17% and an increase in production of 3%. Indirect operating costs decreased by NOK 7.2 billion mainly due to restructuring costs as a result of the merger in 2007 and refund in 2008 of the licence partners' proportional share of the restructuring costs. Operating plant costs increased by NOK 2.7 billion, due to both higher activity and increased pressure on costs in the industry. NOK 1.1 billion is attributed to startup of new fields. Other variable costs increased by NOK 0.8 billion due to loss on sales of assets.

The 60% increase from 2006 to 2007 is due to both an increase in costs of 65% and a decrease in production of 4%. Indirect operating costs increased by NOK 5.5 billion due to restructuring costs as a result of the merger in 2007. Direct operating costs increased by NOK 3.2 billion, due to both higher activity and increased pressure on costs in the industry.

Depreciation, depletion and impairment expenses were NOK 24.0 billion in 2008. Depreciation, depletion and amortisation expenses were NOK 23.0 billion in 2007 and NOK 20.9 billion in 2006. The NOK 1.0 billion increase from 2007 to 2008 was mainly due to higher depreciation costs as a result of higher depreciation offshore due to increased production and changes in the portfolio of producing fields.

The NOK 2.1 billion increase from 2006 to 2007 was mainly due to higher depreciation costs as a result of asset retirement costs and higher depreciation offshore due to changes in the portfolio of producing fields.

Exploration expenditure (including capitalised exploration expenditure) in 2008 amounted to NOK 8.7 billion, compared to NOK 5.7 billion in 2007, and NOK 4.6 billion in 2006. The increase stems primarily from a higher number of wells drilled. The increase in exploration expenditure from 2006 to 2007 was mainly due to increased drilling and seismic activity, as well as to a significant increase in the area fee.

From 2006 to 2007 the drilling expenditure increased by approximately NOK 0.4 billion, while the increase in seismic activity amounted to NOK 0.3 billion. The increase in area fee was due to new regulations on the NCS and it contributed approximately NOK 0.4 billion to the increased costs.

Exploration expenses in 2008 were NOK 5.5 billion, compared to NOK 3.6 billion in 2007, and NOK 3.5 billion in 2006, mostly due to more wells being drilled.

In 2008, 39 exploration and appraisal wells and nine exploration extension wells were completed on the NCS, of which 27 exploration and appraisal wells and six exploration extension wells were discoveries. In 2007, 24 exploration and appraisal wells and two exploration extension wells were completed. Of these, 16 exploration and appraisal wells and both exploration extension wells resulted in discoveries.

In 2006, 18 exploration and appraisal wells and five exploration extension wells were completed, of which eight appraisal and exploration wells and two exploration extension wells were discoveries.

Drilling of seven exploration and appraisal wells were ongoing at the end of the fourth quarter of 2008. Ten exploration and appraisal wells have been completed since 31 December 2008. Of these, eight exploration and appraisal wells were discoveries: Obesum2, Visund S1, Dompap/Måke sidetrack, Fulla, Curran, Pan sidetrack, Katla and Asterix. Verona and Obelix were dry.

The reconciliation of exploration expenditure with exploration expenses is shown in the table below.

	Twelve months ended 31 December				
Exploration (in NOK billion)	**2008**	**2007**	**08 -07 Change**	**2006**	**07-06 Change**
Exploration expenditure (activity)	**8.67**	5.75	51%	4.65	24%
Expensed, previously capitalized exploration expenditure	**0.75**	0.05	1,398%	0.18	(72%)
Capitalized share of current period's exploration activity	**(3.89)**	(2.16)	(80 %)	(1.35)	(60%)
Exploration expenses	**5.53**	3.64	52 %	3.48	5%

Net operating income in 2008 was NOK 166.9 billion compared to NOK 123.2 billion in 2007 and NOK 135.1 billion in 2006. The NOK 43.7 billion increase in 2008 was mainly due to price and volume effects and NOK 5.5 billion in restructuring and other costs arising from the merger in 2007.

The NOK 11.9 billion decrease from 2006 to 2007 was mainly due to price and volume effects, NOK 5.5 billion in restructuring and other costs arising from the merger, higher operating costs of NOK 3.2 billion, mainly due to higher operation and maintenance costs and well maintenance, increased depreciation, mainly due to higher asset retirement costs, which contributed NOK 2.1 billion to the decrease, an increase in other operating expenses of NOK 1.0 billion and processing and transportation costs increasing by NOK 0.4 billion in 2007.

4.1.4.2 Outlook

We expect to continue our high level of exploration activity in 2009 and we plan to drill approximately 30-35 exploration wells on the NCS. A significant part of the drilling activity is expected to take place in mature areas close to existing infrastructure.

We also plan to drill wells in frontier areas of the Norwegian Sea and in the Barents Sea. We have secured rig capacity for our drilling activity level in 2009.

A plan for development and operation (PDO) of the Goliat field in the Barents Sea has been submitted to the Government by the operator Eni. StatoilHydro has a 35% share in the field.

In the period leading up to 2012, several new fields are expected to commence production. Gjøa, Vega/Vega Sør and Morvin are expected to commence production in 2010, while the BP-operated Skarv field is expected to commence production in 2011.

Yttergryta. Yttergryta is the first field that StatoilHydro as a joint company has developed from PDO to production start.

Three new fields will commence production during 2009: Yttergryta has already started producing, while Alve and Tyrihans will commence production later.

4.1.5 International Exploration & Production

Our strategy is to develop key positions in four focus areas: deep water, heavy oil, gas value chains and harsh environments. It is also the framework for new growth and portfolio optimisation.

International exploration activities in 2008 have focused on high-grading our portfolio with strict prioritisation and sequencing of the drilling targets. Forty exploration and appraisal wells were completed in 2008 and, at year end, eight of these were considered to be discoveries or confirmed discoveries. At year end, nine wells were pending final evaluation. The total exploration expenses were NOK 9.2 billion in 2008, compared with NOK 7.7 billion in 2007.

Our international entitlement production was 290 mboe per day in 2008 compared with 307 mboe per day in 2007. The average daily equity production of oil and gas was 465 mboe per day in 2008, compared with 422 mboe in 2007. ***Equity volumes*** represent produced volumes under a PSA contract that corresponds to StatoilHydro's percentage ownership in a particular field. ***Entitlement volumes***, on the other hand, represent StatoilHydro's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Entitlement volumes lifted is the basis for revenue recognition, while equity production volumes affect operating costs more directly. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Acquisitions in 2008 included the purchase of 50% of the Peregrino project in Brazil, making StatoilHydro 100% owner and operator of the field. StatoilHydro formed a strategic alliance with Chesapeake Energy Corporation and acquired a 32.5% interest in Chesapeake's Marcellus shale gas acreage in onshore USA. We closed the sale of all our shallow water assets on the shelf in the Gulf of Mexico (GoM) to Mariner Energy, Inc. and divested our interests in the UK fields Dunlin (28.76%) and Merlin (2.35%).

The total capital expenditure of NOK 48.7 billion in 2008 was higher than in previous years, triggered by many projects under development in addition to the acquisition of new assets to secure longer-term growth, such as Peregrino in Brazil and Marcellus Shale acreage in USA.

4.1.5.1 Profit and loss analysis

INT generated total revenues of NOK 46.1 billion in 2008 and net operating income was NOK 12.8 billion. The average daily entitlement production of liquid was 232 mbbl and the average daily entitlement production of gas was 59 mboe.

			Twelve months ended 31 December		
Income statement (in NOK billion)	**2008**	**2007**	**08-07 Changes**	**2006**	**07-06 Changes**
Total revenues and other income	**46.1**	41.6	11%	32.6	28%
Purchase, net of inventory variation	**1.7**	1.9	(12%)	1.0	93%
Operating expenses	**5.6**	5.4	4%	4.2	31%
Selling, general and administrative expenses	**3.2**	3.3	(4%)	2.0	65%
Depreciation, amortisation and impairment	**13.7**	11.1	23%	14.4	(23%)
Exploration expenses	**9.2**	7.7	19%	7.2	7%
Total expenses	**33.3**	29.4	13%	28.7	3%
Net operating income	**12.8**	12.2	5%	3.9	210%
Operational data:					
Liquids price (USD/bbl)	**88.7**	69.1	28%	60.9	13%
Liquids price (NOK/bbl)	**499.3**	404.8	23%	391.0	4%
Liftings:					
Liquids (mboe per day)	**210.8**	250.0	(16%)	191.4	31%
Natural gas (mboe per day)	**58.9**	54.9	7%	40.2	37%
Total liquids and gas liftings (mboe per day)	**269.7**	304.8	(12%)	231.6	31%
Production:					
Entitlement liquids (mboe per day)	**231.5**	252.2	(8%)	193.7	30%
Entitlement natural gas (mboe per day)	**58.9**	55.0	7%	40.2	37%
Total entitlement liquids and gas production (mboe per day)	**290.5**	307.2	(5%)	233.9	31%
Total equity liquids and gas production (mboe per day)	**464.7**	422.1	10%	303.5	39%

We generated **total revenues** of NOK 46.1 billion in 2008, compared to NOK 41.6 billion in 2007 and NOK 32.6 billion in 2006. The increase from 2007 to 2008 was mainly related to a 19% increase in realised liquid and gas prices, which contributed NOK 7.7 billion, gain from sale of assets, and income from affiliated companies which contributed NOK 2.2 billion. This was partly offset by a 11% decrease in the lifted volumes, which contributed negatively by NOK 5.4 billion.

The average daily liquid lifting was 211 mbbl in 2008, compared with 250 mbbl in 2007 and 191 mbbl in 2006.

The average daily entitlement production of liquid was 232 mbbl in 2008, compared with 252 mbbl in 2007 and 194 mbbl in 2006. The 9% decrease in average daily liquid production from 2007 to 2008 was mainly related to decreased production from ACG in Azerbaijan due to the Central Azeri gas leakage and Kizomba A in Angola coming off plateau, in addition to overall reduced entitlement volumes from PSA fields due to high realised prices. These decreases were partly offset by start-ups of Agbami in Nigeria and the Saxi-Batuque and Mondo fields in Angola.

The average daily entitlement production of gas was 59 mboe in 2008 (equivalent to 9 mmcm or 331 mmcf), compared to 55 mboe in 2007 (equivalent to 9 mmcm or 309 mmcf) and 40 mboe in 2006 (equivalent to 6 mmcm or 224 mmcf). The 7% increase in daily gas production from 2007 to 2008 was mainly related to ramp-up of production from Shah Deniz in Azerbaijan, and start-up of new gas fields in the GoM in the third and fourth quarter of 2007 (Q, Spiderman, San Jacinto). The increase was partly offset by divestment of the GoM shelf fields with effect from year end 2007 and reduced offtake and maintenance turnaround at the In Salah field in Algeria.

The average daily equity liquid and gas production was 465 mboe per day in 2008, compared with 422 mboe in 2007 and 304 mboe in 2006.

The unit of production cost based on entitlement volumes was USD 7.6 per boe in 2008 compared to USD 5.9 per boe in 2007 and USD 5.8 per boe in 2006. Measured in NOK, it was 42.2 per boe in 2008, 34.4 per boe in 2007 and 37.5 in 2006. The 23% increase in unit of production cost measured in NOK from 2007 to 2008 is mainly due to reduced entitlement production and increased cost related to new fields on stream, increased activity, inflation and industry cost pressure.

The unit of production cost based on equity volumes was USD 4.6 per boe in 2008 compared to USD 4.3 per boe in 2007 and USD4.50 per boe in 2006. Measured in NOK it was 42.2 per boe in 2008, 25.0 per boe in 2007 and 28.9 per boe in 2006. See report section 4.1.9 Financial performance-Strong operational performance-Reported Volumes for a description of entitlement and equity volumes.

Operating, general and administrative expenses decreased by NOK 0.1 to NOK 10.5 billion in 2008 compared to NOK 10.6 billion in 2007 and NOK 7.2 billion in 2006.

Depreciation, depletion and amortisation expenses were NOK 13.7 billion in 2008, compared with NOK 11.1 billion in 2007 and NOK 14.4 billion in 2006. The 23% increase in 2008 compared to 2007 was due to an increased net impairment write-down effect of NOK 0.9 billion mainly related to market conditions, and a NOK 1.7 billion increase in ordinary depreciation mainly due to new assets coming on stream and a change in the proved reserves estimates in 2008, which forms the basis for the unit of production depreciation.

Depreciation, depletion and amortisation expenses were NOK 11.1 billion in 2007, compared with NOK 14.4 billion in 2006. The 23 decrease in 2007 compared to 2006 was mainly due to the NOK 4.9 billion impairment write-down effect on depletion, depreciation and amortisation accounts of US GoM shelf fields and Front Runner in our US portfolio in 2006. This decrease was partly offset by impairment write-downs of NOK 1.2 billion for Lufeng, Front Runner, Thunder Hawk and US GoM shelf fields in 2007. A change in the proved reserves estimates in 2007, which forms the basis for the unit of production depreciation, and increased depreciation from new assets coming on stream also contributed to the increase.

		For the year ended 31 December			
Exploration (in NOK billion)	**2008**	**2007**	**08-07 Changes**	**2006**	**07-06 Changes**
Exploration expenditure (activity)	9.1	8.5	8%	8.7	(3%)
Expensed, previously capitalized exploration expenditure	3.0	1.6	88%	1.3	26%
Capitalized share of current period's exploration activity	(2.9)	(2.4)	(23%)	(2.8)	16%
Exploration expenses	9.2	7.7	20%	7.2	7%

Exploration expenditure was NOK 9.1 billion in 2008, compared with NOK 8.5 billion in 2007 and NOK 8.7 billion in 2006. The increase from 2007 to 2008 was mainly due to more expensive wells, higher field evaluation costs and delineation drilling on the oil sands project in Canada.

Exploration expenses were NOK 9.2 billion in 2008, compared with NOK 7.7 billion in 2007 and NOK 7.2 billion in 2006. The increase from 2007 to 2008 was mainly due to more expensive wells, higher field evaluation cost and delineation drilling on the oil sands project in Canada and impairment write-down effects mainly related to changes in market conditions. The increase was partly offset by an increased capitalisation rate.

In total, 40 exploration and appraisal wells were completed in 2008 and at year end, eight of these were considered to be discoveries or confirmed discoveries. At year end, nine wells were pending final evaluation. In 2007, 47 exploration and appraisal wells were completed, 18 of which were considered discoveries. In 2006, 55 exploration and appraisal wells were completed, 24 of which were considered discoveries.

Net operating income in 2008 was NOK 12.8 billion compared to NOK 12.2 billion in 2007 and NOK -3.3 billion in 2006. The increase was mainly related to the price effect which contributed NOK 7.7 billion and gain from sale of assets and income from affiliated companies of NOK 2.2 billion and other miscellaneous increases of NOK 0.2 billion, partly offset by decreased entitlement production contributing NOK 5.4 billion, increased depreciation, depletion and amortisation of NOK 2.6 billion and exploration NOK 1.5 billion.

4.1.5.2 Outlook

Our exploration strategy remains unchanged, but we have adjusted our exploration activity somewhat due to changes in the oil price. We expect to drill approximately 30-35 international exploration and appraisal wells in 2009.

Ninety-six percent of our projected 2012 production is related to already-sanctioned fields. During 2009 we expect the Gimboa field in Angola and Tahiti and Thunder Hawk fields in the USA to start production. We expect our short term production to be affected by OPEC quotas.

Our exploration strategy remains unchanged as we view exploration as our primary growth tool. We will continue to look at acreage acquisitions in the areas that have high resource potential. However, we have adjusted our exploration activity somewhat due to changes in the oil price environment and therefore expect slightly lower activity in 2009 compared to last year.

Approximately 30-35 international exploration and appraisal wells are expected to be drilled in 2009. Rig capacity has been confirmed for this drilling.

We will continue to develop and execute new projects in the portfolio with a focus on cost consciousness and capital flexibility.

4.1.6 Natural Gas

Gas exports from the NCS reached a record high in 2008 and are expected to grow further.

We are currently the second largest supplier of natural gas to Europe, with a market share of approximately 15% in Europe, including the volumes from the State's Direct Financial Interest. Gas exports from the NCS were at a record level in 2008 and are expected to grow. In 2008, StatoilHydro sold 39.3 bcm entitlement gas. In addition, we sold 32.0 bcm NCS gas on behalf of the SDFI. Most of the gas was sold to European energy providers under long-term contracts. Our market share is approximately 20-25% in Germany and France and approximately 15% in the UK.

Two significant factors strongly influence our financial results: the external sales price and the internal transfer price.

In 2008, natural gas prices reached record highs. Our volume weighted average price was NOK 2.40 per scm in 2008, an increase of 45% from 2007. Most gas supply contracts in Europe are indexed towards oil products, such that a change in oil prices will affect the gas markets with some time delay (6-9 months). Increasing oil prices up until the summer months of 2008 were followed by high prices in the gas markets in late 2008. During the second half of 2008 oil prices fell sharply from more than 140 dollars per barrel to some 40 dollars per barrel. We expect this will affect natural gas prices in 2009.

All of the gas from the NCS sold by the Natural Gas business area is purchased from Exploration & Production Norway (E&PN). Previously, the internal transfer price formula was linked to the oil price for Brent Blend. A new market-based internal price for natural gas was put into effect from 1 January 2008. The transfer price formula for natural gas has been updated to better reflect fundamental changes in the markets for competing energies, i.e. crude oil, developments in natural gas markets and changes in the natural gas sales contracts portfolio. In 2008 the transfer price was NOK 1.87 per scm.

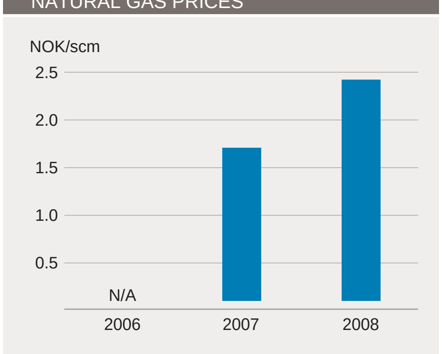
The total capital expenditure of NOK 2.0 billion in 2008 was lower than in previous years, mainly due to fewer pipeline, storage and processing plants being under development.

4.1.6.1 Profit and loss analysis

Total revenues in the Natural Gas business mainly come from gas sales under long-term gas sales contracts and tariff revenues from transportation and processing facilities. Natural Gas generated revenues of NOK 110.8 billion in 2008.

Income statement (in NOK billion)	2008	2007	Twelve months ended 31 December 08 -07 Change	2006	07-06 Change
Total revenues and other income	**110.8**	73.5	51%	97.1	(24%)
Purchase, net of inventory variation	**80.9**	56.7	43%	61.3	(8%)
Operating expenses	**13.8**	12.3	13%	12.1	2%
Selling, general and administrative expenses	**1.3**	1.1	9%	0.5	125%
Depreciation, amortisation and impairment	**2.3**	1.8	25%	1.4	29%
Total expenses	**98.3**	72.0	37%	75.4	(5%)
Net operating income	**12.5**	1.5	739%	21.7	(93%)
Operational data:					
Natural gas sales StatoilHydro entitlement (bcm)	**39.3**	35.6	10%	35.9	(1%)
Natural gas sales (third-party volumes) (bcm)	**5.9**	6.4	(8%)	4.3	49%
Natural gas sales (bcm)	**45.2**	42.0	8%	40.2	4%
Natural gas sales on commission	**1.4**	0.8	79%	NA	-
Natural gas price (NOK/scm)	**2.40**	1.66	45%	NA	-
Transfer price natural gas (NOK/scm)	**1.87**	1.39	34%	1.35	3%
Regularity at delivery point	**100.0%**	100.0%	0%	100.0%	0%

NATURAL GAS PRICES



The total revenues in the Natural Gas business mainly come from gas sales under long-term gas sales contracts and tariff revenues from transportation and processing facilities. Natural Gas generated revenues of NOK 110.8 billion in 2008, compared with NOK 73.5 billion in 2007 and NOK 97.1 billion in 2006. The 51% increase from 2007 to 2008 was mainly due to the high prices for natural gas throughout 2008 compared with 2007, as well as a 10% increase in entitlement sales volumes.

The 24% decrease in total revenues from 2006 to 2007 was mainly due to declining natural gas prices measured in NOK in 2007 and negative changes in fair value of derivatives.

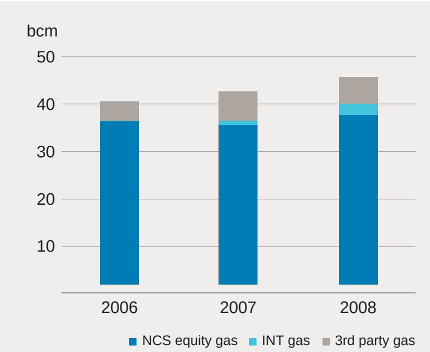
Cost of goods sold increased by 43% from 2007 to 2008 and decreased by 8% from 2006 to 2007. The increase from 2007 to 2008 is mainly related to a 34% increase in transfer price and higher NCS volumes purchased from E&PN. The decrease from 2006 to 2007 is mainly related to a decrease in the third party purchase price of natural gas, partly offset by a slight increase in the transfer price paid to E&PN.

Operating, selling and administrative expenses increased by 12% from 2007 to 2008 mainly due to higher transportation costs related to increased LNG transportation and increased booking of throughput capacity in Gassled in 2008. The 6% increase from 2006 to 2007 is mainly caused by early retirement cost accruals and increased accruals for removal costs.

In 2008, the **net operating income** was NOK 12.5 billion, compared to NOK 1.5 billion in 2007. The volume weighted average sales price increased by 45%, amounting in total to NOK 31.2 billion, of which the rise in European piped gas price contributed NOK 27.0 billion. Changes in European gas prices lag behind changes in crude oil prices.

Net operating income for 2007 was NOK 1.5 billion, compared with NOK 21.7 billion in 2006. The decrease of NOK 20.1 billion was mainly due to a 13% decrease in prices for piped natural gas, which reduced income by NOK 9.5 billion, and negative changes amounting to NOK 10.3 billion in the fair value of derivatives.

NATURAL GAS SALES



With effect from 2008, Natural Gas provides an explanation of the adjusted net operating income from its two main business activities: Processing and Transport and Marketing and Trading. Processing and Transport consists mainly of our share in Gassled and the Technical Service Provider role at Kårstø and Kollsnes. Marketing and Trading consists of our gas sales and trading activities. The Marketing and Trading activity carries the associated transportation costs within the Natural Gas segment. The split between business segments is only restated for 2007.

Net operating income in **Processing and Transport** was NOK 5.6 billion in 2008, compared to NOK 5.6 billion in 2007. Processing and Transport income increased by NOK 0.3 billion, while fixed operating expenses and depreciation increased by NOK 0.3 billion.

Net operating income in **Marketing and Trading** was NOK 7.0 billion in 2008, compared to a loss of NOK 4.1 billion in 2007. Marketing and Trading income increased by NOK 11.1 billion, mainly due to increased price (NOK 31.2 billion) and higher volumes sold (NOK 7.7 billion). The main offsetting factors to the increased income were NOK 24.2 billion in higher costs of goods sold, NOK 1.5 billion in increased operating expenses, NOK 0.5 billion increased depreciation expences, and NOK 0.2 billion increased selling and administrative expenses. The increased operating expenses are mainly due to higher transportation cost in 2008.

Total natural gas sales were 45.2 bcm (1.60 tcf) in 2008, 42.0 bcm (1.48 tcf) in 2007 and 40.2 bcm (1.42 tcf) in 2006. The 8% increase from 2007 to 2008 in gas volumes sold was mainly due to increased entitlement gas sales, but this was partly offset by a net decrease in StatoilHydro third party sales volumes. Third party gas is mainly used for portfolio balancing and optimisation and trading purposes. The increase in entitlement sales volumes mainly relates to higher production from NCS in addition to the first full year with production from Shah Deniz, Azerbaijan. Of the total natural gas sales in 2008, 39.3 bcm (1.39 tcf) was entitlement gas, including 1.4 bcm (0.05 tcf) of gas from Shah Deniz in Azerbaijan and 0.9 bcm (0.03 tcf) from Gulf of Mexico, and 2.6 bcm (0.92 tcf) was the SDFI's share of US piped gas.

The 4% increase from 2006 to 2007 in gas volumes sold was mainly due to increased third-party gas sales, but this was partly offset by a net decrease in StatoilHydro entitlement sales volumes. The decrease in entitlement sales volumes was mainly related to production problems on Kvitebjørn throughout 2007.

The weighted average gas price for our sales was NOK 2.40 per scm in 2008, compared to NOK 1.66 per scm in 2007, an increase of 45%. The increase in price from 2007 to 2008 was mainly due to an increase in prices for oil products (such as gas oil and fuel oil) and other competing energy sources, as well as higher gas prices on the National Balancing Point (NBP) in the UK. The sales of natural gas from In Salah are reported by the International Exploration & Production business area. The weighted average price is only available from 2007.

4.1.6.2 Outlook

The present economic downturn means that there is currently sufficient supply to meet demand. In the longer term, however, the market balance is more uncertain. Increasing transport distances and complexity of new resources suggest an increase in prices.

In the short term, the present economic downturn means that there is sufficient supply in Europe, Asia and North America to meet demand expectations. Balance in supply and demand will probably impact gas prices.

In the longer term, however, the market balance is more uncertain and the current economic impact on long term demand and the development of new gas projects are difficult to assess. Increasing transport distances and complexity of new resources would seem to suggest an upward price trend over time, ensuring sufficient prices to maintain supplies.

The short term gas market is affected by new LNG capacity coming on stream and reduced demand for energy. LNG in the Atlantic basin is responding to changes in prices between major markets, taking advantage of arbitrage opportunities. Our view on these events is that we have value creation potential through increased gas exports due to the proximity and flexibility of our infrastructure to favourable markets.

In the long term, we continue to have a positive view of gas as an energy source for Europe. 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. The trend for LNG as a link between regional markets is expected to continue as more LNG will come on stream, making gas a commodity that is driven by global development.

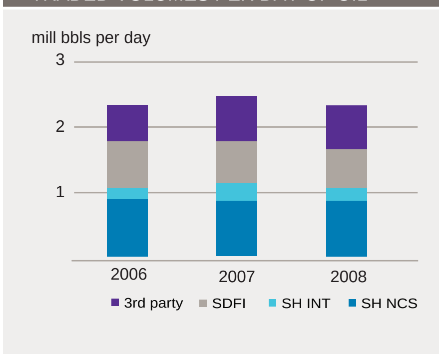
Our gas strategy remains firm. In 2009, we plan to have focus on on extracting maximum value from our long term gas sales portfolio through maintaining daily supply regularity and contract modernisation as a part of regular contract revisions. In addition, we will focus on participating in the short term gas markets in order to add value through balancing, trading and optimisation activities. Business development efforts will be concentrated on commercialising our position in the Shah Deniz field and our newly-acquired gas position in the US. This position in the Marcellus shale gas acreage, in combination with Gulf of Mexico production and our LNG regasification capacity position at Cove Point, will provide a foundation for growth in our US market position in the years to come.

4.1.7 Manufacturing and Marketing

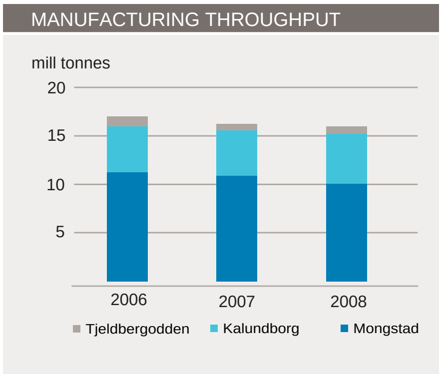
In 2008, we experienced volatile market conditions and a worldwide economic downturn, further emphasising the importance of efficient operations and prudent project execution.

During 2008 we also continued the standardisation and simplification process throughout the business area, in order to increase efficiency.

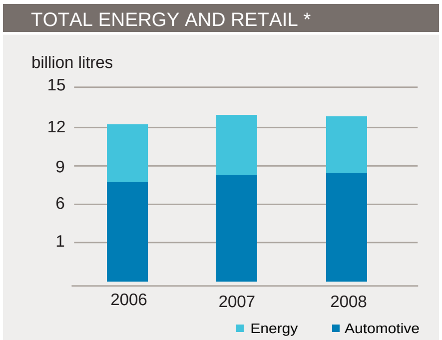
TRADED VOLUMES PER DAY OF OIL



MANUFACTURING THROUGHPUT



TOTAL ENERGY AND RETAIL *



*Sales volume 2008

Our total capital expenditure of NOK 6.8 billion in 2008 was higher than in previous years, triggered by high activity in projects and a major turnaround at the Mongstad refinery. Capital expenditure was NOK 4.8 billion in 2007 and NOK 2.5 billion in 2006.

Oil sales, trading and supply

With average crude and condensate sales of 2 mmbbl per day in 2008, we are one of the world's largest net sellers of crude oil. Of our daily sales of 2 mmbbl, approximately 1.0 mmbbl were our own equity volumes, 0.5 mmbbl were third party volumes and 0.5 mmbbl were SDFI volumes. Including NGL, the average sales volume was 2.3 mmbbl per day in 2008 compared with 2.4 mmbbl per day in 2007. In 2006, the average sales volume was 2.3 mmbbl per day.

We will continue to strengthen our global trading position by securing physical infrastructure and building physical third party positions based on our production in selected regions. Physical activity pertains to an actual commodity, and does not involve trading in financial instruments. The average daily third party crude volumes sold in 2008 were 0.53 mmbbl, compared to 0.52 mmbbl in 2007 and 0.42 mmbbl in 2006. Although 2008 has been a year with high financial uncertainty and increased counterparty risk, no credit losses have been realised on customer sales during the year.

Manufacturing

Mongstad had a challenging year with their largest ever turnaround including major modifications in the cracker unit, as well as some unplanned shutdowns. Kalundborg had significant shutdowns in 2008, partly unplanned and partly due to start-up after the fuel reduction project. Sture had stable operations and high regularity, and Tjeldbergodden had high regularity and utilisation in 2008.

Energy and retail

We have maintained our leading energy and retail positions and have the leading or second largest market share in most of the countries in which we operate.

On 21 October 2008, the European Commission granted permission for StatoilHydro to take over the bulk of the Jet self-service retail chain in Scandinavia from ConocoPhillips. To comply with the terms set by the commission, StatoilHydro agreed to sell 80 of the 274 filling stations acquired. StatoilHydro will also be obliged to sell 118 Hydro stations in Sweden as part of the divestment package.

The transaction is an important element in our endeavours to become the leading fuel company in Scandinavia.

We also continued to strengthen our position as one of the leading suppliers of biofuels in Scandinavia and the Baltic countries during 2008. Biofuels are now available at more than 1,300 service stations in seven different countries.

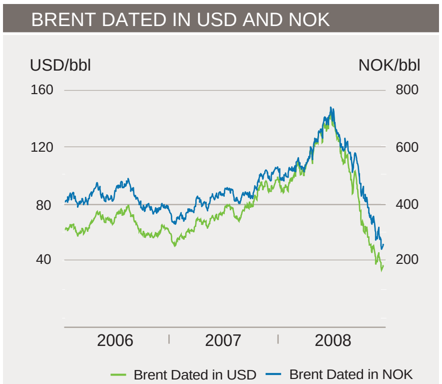
4.1.7.1 Profit and loss analysis

In Manufacturing and Marketing, total revenues and other income increased to NOK 531 billion, mainly due to higher oil prices.

Total revenues and other incomeincreased from NOK 428 billion in 2007 to NOK 531 billion in 2008. The increase from 2007 to 2008 was mainly due to higher prices on crude and other oil products. The average crude price in USD increased by approximately 40% in 2008 compared to 2007, but was partly offset by the weakening of the average USD exchange rate by almost 4%.

IFRS income statement (in NOK billion)	2008	2007	Twelve months ended 31 December 08-07 Changes	2006	07-06 Changes
Total revenues and other income	**531.3**	428.1	24%	411.8	4.0%
Purchase, net of inventory variation	**501.4**	401.8	25%	383.4	5%
Operating expenses	**14.7**	12.6	16%	11.8	7%
Selling, general and administrative expenses	**8.6**	7.0	23%	7.1	(2%)
Depreciation, amortisation and impairment	**2.1**	2.8	(25%)	2.3	20%
Total expenses	**526.8**	424.2	24%	404.6	5%
Net operating income	**4.5**	3.9	14%	7.2	(86%)
Operational data:					
FCC margin (USD/bbl)	**8.2**	7.5	9%	7	5%
Contract price methanol (EUR/tonne)	**344.0**	317.0	9%	300	5%

BRENT DATED IN USD AND NOK



The increase from 2006 to 2007 was mainly due to higher prices and volumes for crude and gas oil products. The average oil price increased by 12% in 2006 compared to 2007, which was partly offset by the weakening of the average USD exchange rate by almost 9% in 2006 compared to 2007.

Cost of goods sold increased from NOK 402 billion in 2007 to NOK 501 billion in 2008, primarily due to increased prices on volumes purchased. The increase of 5% from 2006 to 2007 was also a result of increased crude oil prices and purchased volumes.

Operating, selling and administrative expenses increased by 19% in 2008 compared with 2007. This was due to increased transportation costs of NOK 0.7 billion for shipments of crude made to Asia in 2008, and a provision of NOK 1.3 billion for an expected increased cost related to a take or pay contract at Mongstad. Manufacturing incurred increased operating costs in 2008 due to high maintenance activity. During 2007 there were additional costs associated with provisions for pension liabilities of NOK 0.7 billion included in restructuring costs relating to the merger.

Costs increased by 3% in 2007 compared with 2006, mainly due to the provision for pension liabilities of NOK 0.7 billion.

Depreciation, amortisation and impairment totalled NOK 2.1 billion in 2008, compared with NOK 2.8 billion in 2007. The decrease was mainly due to an impairment loss of NOK 0.95 billion in 2007 in Energy & Retail Sweden, of which NOK 0.5 billion was included in restructuring costs relating to the merger.

The increase of 24% in 2007 compared with 2006 was a result of impairment writedowns in 2007.

In 2008, **net operating income** was NOK 4.5 billion, compared with NOK 3.8 billion in 2007. The increase was primarily due to a net positive effect of NOK 2.4 billion relating to operational and commercial storage valuation changes, a large positive effect due to currency and a negative effect due to price changes. In addition, there were pension cost provisions of NOK 0.7 billion in 2007. Impairment losses and provisions in connection with restructuring of the retail business in Sweden were NOK 0.5 billion lower in 2008 compared to 2007. Negative effects in 2008 when compared to 2007 included an expected increased cost related to a take or pay contract of NOK 1.3 billion and lost revenues due to the turnaround undertaken at Mongstad.

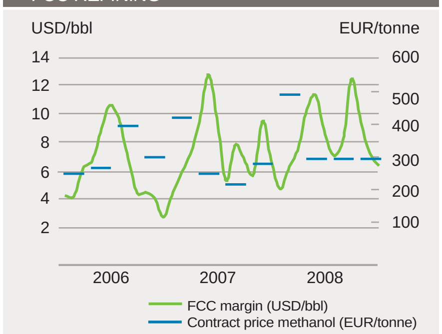
The NOK 3.4 billion decrease from 2006 to 2007 was mainly due to increased retirement pension costs of NOK 0.7 billion, negative currency effects of NOK 0.7 billion, a decrease in trading results of NOK 0.6 billion, and impairment loss and provisions of NOK 0.5 billion due to weak market conditions and restructuring of the retail business in Sweden. A gain of NOK 0.6 billion was also achieved in 2006 from the sale of our retail business in Ireland.

Oil Sales, trading and supply

In 2008, net operating income was NOK 4.2 billion, compared with NOK 1.3 billion in 2007. The good result in 2008 was mainly due to a net positive effect of NOK 2.8 billion relating to operational and commercial storage valuation changes. The overall trading results improved, but within product trading we experienced negative trading results, leading to a scaling down of product trading by the end of the year.

The decrease of NOK 0.9 billion from 2006 to 2007 was mainly due to NOK 0.7 billion in currency losses, lower trading results of NOK 0.6 billion compared with 2006 and a deferred gain on inventories, which was partly offset by gains on operational storage.

FCC REFINING*



*FCC Refining margin and quarterly methanol price

Manufacturing

In 2008, net operating income was NOK 0.7 billion, compared with NOK 3.3 billion in 2007. The decrease in 2008 was mainly due to a provision for a take-or-pay contract of NOK 1.3 billion, a large turnaround at Mongstad, and high operating costs due to the increased activity levels in maintenance, modifications and business development. Margins were low at Mongstad due to the turnaround, but improving at Kalundborg due to the fuel reduction project and good feedstock optimisation. The average contract price for methanol increased by 9% from EUR 317/tonne in 2007 to EUR 344/tonne in 2008.

The NOK 1.1 billion decrease from 2006 to 2007 was mainly due to lower regularity and higher operating costs due to turnaround activities. The lower USD/NOK exchange rate and lower capacity utilisation also contributed negatively. Margins were good at Mongstad, but they were lower than expected at Kalundborg due to high crude differentials and the delay in the fuel reduction project. The average contract price for methanol increased by 6% from EUR 300/tonne in 2006 to EUR 317/tonne in 2007.

Energy and retail

Net operating loss was NOK 0.2 billion in 2008, compared with NOK 17 million in 2007. We experienced increased revenues during 2008, mainly due to a large increase in transport fuel market prices, and a small increase in sales volumes at our outlets, from 8.3 billion to 8.4 billion litres. The decrease in total net income was mainly due to increased operating costs coupled with negative effects from storage valuation changes. Costs related to the restructuring of our retail business in Sweden were reduced from NOK 1.1 billion in 2007 to NOK 0.5 billion in 2008.

The NOK 0.6 billion decrease from 2006 to 2007 was mainly due to increased impairment loss and provisions from NOK 0.6 billion in 2006 to NOK 1.1 billion in 2007, due to weaker market conditions and restructuring of our retail business in Sweden. There was also a net gain of NOK 0.6 billion in 2006 related to the sale of our retail business in Ireland. These effects were offset to some extent by an increase of 8% in transport fuel volumes at our outlets, from 7.7 billion to 8.3 billion litres, together with an increase in margins. During the same period, margins on convenience products rose by 15%.

4.1.7.2 Outlook

2009 will be a challenging year with lower crude prices, an overcapacity situation in Europe, and high volatility in all our markets. In the long term, growth areas are expected to be biofuels, transportation fuel and convenience sales.

Oil sales, trading and supply

The year 2008 was the most volatile period in the product, gas liquids and crude oil markets. Dated Brent entered the year on a strong upward trend extending from 2007 and then accelerating as financial investors increased positions in a search for more favourable yields, thus exacerbating the upward trend. Strong support from a tight gasoil/diesel market and declining crude oil inventories led to an increasingly tight oil market and dated Brent crude prices reached a record level of 144 USD/bbl on 3 July 2008. However, several signals started to discourage investors; an underlying tendency of slower global GDP growth, weak product demand, especially in the US, and rising OECD stocks after a period of increased OPEC output. As these factors became ever more apparent, the financial crisis intensified and crude oil prices peaked and started a sharp fall during the autumn of 2008 prompting OPEC to scale back production. Increased risk aversion and a need for cash induced investors to sell in liquid markets to cover losses in illiquid ones, gave commodities a disproportionally large share of the sell-off. With a shift of both sentiment and outlook during 2008, crude oil prices were fundamentally different in the first half of the year compared to the second and traded at around 40 USD/bbl by the end of December.

Manufacturing
The demand for refined products around the Atlantic basin is expected to decrease and lead to surplus capacity, especially for gasoline. Rationalisation of European refining capacity is required to maintain healthy margins. Competitive profitability and survival will very much depend on location, the ability to utilise the available feedstock and deliver the optimal product qualities, and cost level. The average crude oil barrel is becoming more sour and heavier. As both the heavy and light ends have increased, product specifications have become more stringent, and the demand for fuel oil is falling. All these factors necessitate additional processing flexibility and capacity, and continued investment in fuel oil conversion is expected. Bio-components are expected to grow in market share. After heavy cost-cutting in the 1990s, good margins in the current decade have increased the focus on reliability and utilisation. In combination with high pressure in the labour and contractor markets, this has led to heavy cost increases. Falling margins and general recession is expected to significantly increase management attention on operating and investment costs.

Methanol prices were expected to return to a moderate level as new capacity in stranded gas areas became available, but the financial turmoil has caused an earlier and deeper price decline. Europe is expected to continue to be a net importer of methanol, and European producers will therefore still have a geographical advantage.

Energy and retail
2009 will be a very challenging year, but in the long term the main growth areas are expected to be transportation fuel, mainly due to the anticipated growth in the diesel sector, and convenience sales.

We are reinforcing our long-term ambition of sales growth in Eastern Europe, though in 2009 this will be limited due to investment constraints. We continued to expand our station network in Poland during 2008 and recently entered the St. Petersburg market in Russia. We already have a strong foothold in the Baltic countries, but 2008 was a challenging year due to the economic downturn experienced in the region.

The acquisition of Jet in Scandinavia will allow us to strengthen our Scandinavian retail fuel position.

We believe that use of heavy oil products in the stationary energy sector will gradually be replaced by either gas carriers (LNG and LPG), or other non-fossil energy carriers.

4.1.8 Eliminations and other operations

Eliminations and other operations for the years ending 31 December 2008, 2007 and 2006.

Other operations consist of the activities of Corporate Services, Corporate Centre, Group Finance and the two corporate technical service providers, Technology and New Energy and Projects.

In connection with our other operations, we recorded a net operating loss of NOK 0.7 billion in 2008, compared with a loss of NOK 2.3 billion in 2007 and a loss of NOK 1.9 billion in 2006. The increase from 2007 to 2008 is primarily due to a gain related to the sale of IS Partner AS in 2008 and that no provisions were made for early retirement costs and other restructuring costs in 2008, as compared to 2007, when provisions were made in relation to early retirement and pension benefits due to the merger. The increase was partly offset by increased costs because of higher activity.

4.1.9 Reported volumes

Here we explain some of the terms used when reporting our volumes, such as lifted entitlement volumes, produced (equity) volumes, equity volumes, entitlement volumes and proved reserves.

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

Volumes of lifted oil and natural gas correlate over time with production, but they may be higher or lower than production for the period due to operational factors that affect the timing of when StatoilHydro-chartered vessels lift the oil from the fields. Volumes of natural gas produced on the NCS are deemed to be equal to lifted volumes of natural gas from the NCS.

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

Equity volumes represent produced volumes under a PSA contract that correspond to StatoilHydro's percentage ownership in a particular field. ***Entitlement volumes***, on the other hand, represent StatoilHydro's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes. The main country in which we operate under PSAs are Algeria, Angola, Azerbaijan, Libya, Nigeria and Russia.

Proved reserves are entitlement volumes recognised as reserves in accordance with SEC Rule 4-10 (a) and relevant guidance. They represent volumes that with reasonable certainty will be produced and to which we will have entitlement in the future. See note 34-Supplementary oil and gas information in the consolidated statements in this report for details about how we measure and report on proved reserves.

4.2 Liquidity and capital resources

Cash flow provided by operating activities was NOK 102.5 billion in 2008, while cash flow used in investing activities was NOK 85.8 billion. As of 31 December 2008, we had liquid assets of NOK 28.4 billion.

CONSOLIDATED BALANCE SHEETS

	Twelve months ended 31 December		
(in NOK billion)	**2008**	**2007**	**2006**
ASSETS			
Non-current assets			
Property, plant and equipment	**329.8**	278.4	272.2
Intangible assets	**66.0**	44.9	31.2
Associated companies	**12.6**	8.4	8.6
Deferred tax assets	**1.3**	0.8	0.8
Pension assets	**0.0**	1.6	1.1
Financial investments	**16.5**	15.3	14.0
Derivative financial instruments	**2.4**	0.6	0.5
Financial receivables	**4.9**	3.5	4.3
Total non-current assets	**433.6**	353.5	332.6
Current assets			
Inventories	**15.2**	17.7	15.3
Trade and other receivables	**69.9**	69.4	62.4
Current tax receivable	**3.8**	0.0	18.7
Derivative financial instruments	**27.5**	21.1	21.3
Financial investments	**9.8**	3.4	1.0
Cash and cash equivalents	**18.6**	18.3	7.5
Total current assets	**144.8**	129.8	126.2
TOTAL ASSETS	**578.4**	483.2	458.8

CONSOLIDATED BALANCE SHEETS

(in NOK billion)	Twelve months ended 31 December 2008	2007	2006
EQUITY AND LIABILITIES			
Equity			
Share capital	**8.0**	8.0	8.0
Treasury shares	**0.0**	0.0	0.0
Additional paid-in capital	**41.5**	41.4	44.6
Additional paid-in capital related to treasury shares	**(0.6)**	(0.4)	(3.6)
Retained earnings	**148.0**	140.9	122.2
Other reserves	**17.3**	(12.6)	(3.4)
StatoilHydro shareholders' equity	**214.1**	177.3	167.8
Minority interest	**2.0**	1.8	1.6
Total equity	**216.1**	179.1	169.4
Non-current liabilities			
Financial liabilities	**54.6**	44.4	49.2
Deferred tax liabilities	**68.1**	67.5	72.1
Pension liabilities	**25.5**	19.1	11.0
Accruals and other provisions	**54.4**	43.8	42.2
Total non-current liabilities	**202.7**	174.8	174.6
Current liabilities			
Trade and other payables	**61.2**	64.6	55.6
Current tax payable	**57.1**	50.9	47.1
Financial liabilities	**20.7**	6.2	5.6
Derivative financial instruments	**20.8**	7.6	6.5
Total current liabilities	**159.7**	129.4	114.9
Total liabilities	**363.4**	304.2	289.4
TOTAL EQUITY AND LIABILITIES	**578.4**	483.2	458.8

Other financial information	2008	For the year ended 31 December 2007	2006
Net debt to capital employed (GAAP basis) [1]	**17.7%**	13.9%	21.4%
Net debt to capital employed [2]	**17.5%**	12.4%	20.5%
After-tax return on average capital employed (GAAP basis) [3]	**21.0%**	17.7%	22.7%
After-tax return on average capital employed [4]	**21.1%**	19.9%	22.9%

1) As calculated according to GAAP. Net debt to capital employed is the net debt divided by capital employed. Net debt is interest-bearing debt less cash and cash equivalents and short-term investments. Capital employed is net debt, shareholders' equity and minority interest.

2) As adjusted. In order to calculate the net debt to capital employed ratio that our management makes use of internally and which we report to the market, we make adjustments to capital employed as it would be reported under GAAP to adjust for project financing exposure that does not correlate to the underlying exposure and to add into the capital employed measure interest-bearing elements which are classified together with non-interest-bearing elements under GAAP. See report section Use and Reconciliation of Non-GAAP Financial Measures for a reconciliation of capital employed and a description of why we make use of this measure.

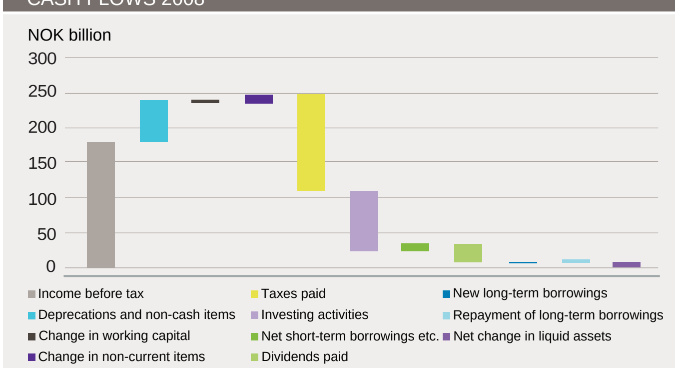
3) As calculated in accordance with GAAP. After-tax return on average capital employed (ROACE) is equal to net income before minority interest and before after-tax net financial items, divided by average capital employed over the last 12 months.

4) As adjusted. This figure represents ROACE computed on the basis of capital employed, adjusted as indicated in footnote 2 above. See Use and Reconciliation of Non-GAAP Financial Measures for a reconciliation of return on average capital employed and a description of why we make use of this measure.

in (%)	2008	For the year ended 31 December 2007	2006
Ratio of earnings to fixed charges	**52.1%**	19.6%	21.2%

Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortization of capitalized interest and (iv) fixed charges (which have been adjusted for capitalized interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalized interest) and estimated interest within operating leases.

CASH FLOWS 2008



Cash flows from operating activities

Our primary source of cash flow consists of funds generated from operations. Cash flow provided by operating activities was NOK 102.5 billion in 2008, compared to NOK 93.9 billion in 2007. The NOK 8.6 billion increase was due to an increase in cash flows from underlying operations of NOK 44.1 billion and cash flows from other non-current items related to operating activities of NOK 5.9 billion. These effects were partly offset by an increase in taxes paid of NOK 37.2 billion and negative cash flows from changes in working capital of NOK 4.3 billion.

Net cash flows generated from operations for 2007 were NOK 93.9 billion, compared to NOK 88.6 billion in 2006. The increase of NOK 5.3 billion in cash flows from operating activities from 2006 to 2007 was mainly due to changes of NOK 12.4 billion in working capital, a decrease of NOK 8.6 billion in non-current items related to operating activities and a decrease of NOK 5.8 billion in taxes paid. These increases were partly offset by a decrease of NOK 21.5 billion in cash flows from underlying operations.

Condensed cash flow statement (in NOK billion)	2008	2007	Twelve months ended 31 December Changes	2006	Changes
Cash flows from underlying operations	**239.9**	195.7	44.1	208.6	(12.8)
Cash flows from (to) changes in working capital	**(3.8)**	0.5	(4.3)	(11.9)	12.4
Taxes paid	**(139.6)**	(102.4)	(37.2)	(108.2)	5.8
Other changes	**6.1**	0.1	5.9	0.1	(0.0)
Cash flows provided by operations	**102.5**	93.9	8.6	88.6	5.3
Acquisitions	**(13.1)**	0.0	(13.1)	0.0	0.0
Additions to PP&E and intangible assets	**(76.2)**	(75.5)	(0.6)	(59.9)	(15.7)
Proceeds from sales	**5.4**	1.1	4.3	3.4	(2.3)
Other changes	**(1.9)**	(0.7)	(1.3)	(0.7)	0.1
Cash flows to investments	**(85.8)**	(75.1)	(10.7)	(57.2)	(17.9)
Net change in long-term borrowing	**(0.3)**	(1.2)	0.9	(2.2)	1.0
Net change in short-term borrowing	**10.4**	0.8	9.7	(9.7)	10.5
Dividends paid	**(27.1)**	(25.7)	(1.4)	(17.8)	(7.9)
Other changes	**(0.1)**	18.1	(18.3)	(1.8)	19.9
Cash flows used in financing activities	**(17.0)**	(7.9)	(9.1)	(31.4)	23.5
Net increase (decrease) in cash flows	**(0.3)**	10.9	(11.2)	0.0	10.9

Cash flows used in investing activities
Cash flow used in investing activities was NOK 85.8 billion in 2008, compared to NOK 75.1 billion in 2007. The NOK 10.7 billion increase is mostly related to the NOK 13.1 billion in payments related to recent acquisitions, NOK 3.6 billion in increased investments in other intangible assets and NOK 2.3 billion in increased capitalisation of exploration expenditures, partly offset by NOK 5.3 billion worth of lower investments in property, plant and equipment and NOK 4.3 billion in higher proceeds from sales of assets.

Approximately 50% of the investments in 2008 are investments in assets expected to contribute to growth in oil and gas production, while approximately 35% relate to investments in currently producing fields, and the remaining 15% represent investments in StatoilHydro's other activities.

Net cash flows used in investing activities amounted to NOK 75.1 billion in 2007, compared with NOK 57.2 billion in 2006. The NOK 17.9 billion increase was mostly related to NOK 15.7 billion in higher investments in property plant and equipment and NOK 2.3 billion in less proceeds from sales of assets in 2007 compared to 2006.

Gross investments are defined as additions to property, plant and equipment (including intangible assets and long term share investments) and capitalised exploration expenditure. Gross investments were NOK 95.4 billion in 2008, compared to NOK 75.0 billion in 2007. The difference between cash flows used in investing activities and gross investments in 2008 compared to 2007 was related to acquisition of assets and proceeds from sales of assets.

Gross investments amounted to NOK 75.0 billion in 2007, compared to NOK 64.3 billion in 2006.

Gross investments (in NOK billion)	2008	2007	For the year ended 31 December Change	2006	Change
E&P Norway	**34.9**	31.1	12%	29.2	6%
International E&P	**48.7**	36.2	35%	28.9	25%
Natural Gas	**2.0**	2.1	(6%)	3.2	(34%)
Manufacturing & Marketing	**8.5**	4.8	76%	2.5	93%
Other	**1.3**	0.8	73%	0.5	63%
Total gross investments	**95.4**	75.0	27%	64.3	17%

The difference between cash flows used in investing activities and gross investments in 2007 was mainly related to the effects of changes in long-term loans granted and other long-term items offset by proceeds from the sale of assets. In addition to the investments included in the table above, NOK 2.4 billion in LNG-related assets has been transferred from E&P Norway to the Natural Gas business area.

Reconciliation of cash flow to gross investments (in NOK billion)	For the year ended 31 December 2008	2007	2006
Cash flows to investments	**85.8**	75.1	57.2
NCS portfolio transactions	**0.0**	0.0	0.1
Capital leases	**0.0**	0.0	2.4
Proceeds from sales of assets	**5.4**	1.1	3.4
Other changes in non-current loans granted and JV balances	**4.2**	(1.2)	1.2
Gross investments	**95.4**	75.0	64.3

Cash flows used in financing activities
Net cash flows used in financing activities in 2008 amounted to NOK 17.0 billion, compared to NOK 7.9 billion in 2007. The NOK 9.1 billion increase was mainly related to a decrease of the demerger balance with Norsk Hydro of NOK 18.7 billion in combination with increased dividend paid NOK 1.4 billion. These effects were partly offset by increased financial liabilities of NOK 10.5 billion in 2008, mainly related to collateral and commercial papers.

New long-term borrowings at 31 December 2008 were NOK 2.6 billion, compared to NOK 1.7 billion at 31 December 2007. The repayment of long-term debt at 31 December 2008 was NOK 2.9 billion compared with NOK 2.9 billion at 31 December 2007.

Cash flows used in financing activities in 2008 included a dividend of NOK 27.1 billion paid by Statoil ASA to shareholders related to the annual accounts for 2007, while the dividend paid by Statoil ASA to its shareholders in 2007 relating to the annual accounts for 2006 was NOK 25.7 billion.

Net cash flows used in financing activities in 2007 amounted to NOK 7.9 billion, compared to NOK 31.4 billion in 2006. The decrease in cash flows used in financing activities from 2006 to 2007 was mainly related to the settlement of the demerger balance with Norsk Hydro ASA on 1 October 2007, which was partly offset by increased dividends paid in 2007 compared to 2006.

New long-term borrowings as of 31 December 2007 were NOK 1.7 billion, compared to NOK 0.1 billion at 31 December 2006. The repayment of long-term debt at 31 December 2007 was NOK 2.9 billion compared with NOK 2.3 billion at 31 December 2006. Cash flows used in financing activities in 2007 included a dividend of NOK 25.7 billion paid by Statoil ASA to shareholders related to the annual accounts for 2006, while the dividend paid by Statoil ASA to its shareholders in 2006 relating to the annual accounts for 2005 was NOK 17.8 billion.

Current items
Current items (total current assets minus total current liabilities) were negative NOK 14.9 billion at 31 December 2008, compared to positive NOK 0.4 billion at 31 December 2007.

The change was mainly due to an increase in current liabilities such as accounts payable of NOK 3.8 billion, taxes payable of NOK 6.1 billion, derivatives of NOK 13.1 billion, collateral of NOK 7.7 billion, commercial papers of NOK 3.0 billion and current portion of non-financial liabilities of NOK 4.0 billion, in combination with a decrease in inventories of NOK 2.5 billion. These factors were partly offset by a decrease in accounts payable with related parties of NOK 7.2 billion in combination with an increase in current assets such as accounts receivable of NOK 2.9 billion, joint venture receivables of NOK 1.0 billion, derivatives of NOK 6.4 billion and current financial investments of NOK 6.4 billion.

Current items were NOK 25.5 billion as of 31 December 2007, compared to NOK 43.8 billion as of 31 December 2006. The decrease in net non-current financial liabilities from 2006 to 2007 was mainly related to an increase of NOK 13.1 billion in liquid assets, in combination with a decrease of NOK 4.8 billion in gross non-current financial liabilities due to the weakening of the USD in relation to NOK during 2007.

We believe that taking into consideration StatoilHydro's established liquidity reserves (including committed credit facilities), and StatoilHydro has sufficient working capital for foreseeable requirements, credit rating and access to capital markets, we are well positioned to execute the planned long-term funding in the first half of 2009. Our sources of liquidity are described below.

Liquidity
Our annual cash flow from operations is highly dependent on oil and gas prices and our levels of production, and is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside our control, will cause changes in our cash flows. We will use available liquidity to finance Norwegian petroleum tax payments (due on 1 February, 1 April, 1 June, 1 October and 1 December each year), any dividend payment and investments. Our investment programme is spread over the year. There may be a gap between funds from operations and funds required to fund investments, which will be financed by short and long-term borrowings. We intend

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 StatoilHydro carries out different risk assessments, some of them in line with financial matrixes 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 was raised to AA- in August 2007, reflecting the majority ownership by the Norwegian State. Standard & Poor's short-term rating of StatoilHydro is A-1+. The current rating outlook is stable from both agencies.

As of 31 December 2008, we had liquid assets of NOK 28.4 billion, including NOK 18.6 billion in cash and cash equivalents and NOK 9.7 billion of current financial investments (domestic and international capital market investments). Approximately 29% of our liquid assets were held in EUR-denominated assets, 6% in NOK and 58% in USD, 3% in GBP and 4% in other currencies, before the effect of currency swaps and forward contracts.

As of 31 December 2007, we had liquid assets of NOK 21.6 billion, including NOK 18.3 billion in cash and cash equivalents and NOK 3.4 billion of current financial investments (domestic and international capital market investments). Approximately 54% of our liquid assets were held in EUR-denominated assets, 26% in NOK and 20% in USD, before the effect of currency swaps and forward contracts.

Compared to year end 2007, current financial investments increased by NOK 6.4 billion during 2008, and cash and cash equivalents increased by NOK 0.4 billion. The increase of liquid assets during 2008 was mainly due higher cash inflows from increased revenues in 2008 compared to 2007, partly offset by higher investments in 2008 compared to 2007. The average liquids price increased from USD 72 (NOK 423) per barrel in 2007 to USD 97 (NOK 548) per barrel in 2008.

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

As of 31 December 2008, the group 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 was entered into by us in 2004, and, after exercising of an extension option in 2006, it is available for drawdowns until December 2011. At year end 2008, no amounts had been drawn under the revolving credit facility. In 2008 we drew down a line of credit established in our favour on a bilateral basis by an international financial institution. The loan is denominated in USD and has a final maturity of five years.

StatoilHydro plans to issue bonds in 2009 to secure necessary financial flexibility going forward. As a part of this plan, the group utilised the updated EMTN program in March 2009 to issue a GBP 800 million bond with a 22 year tenure, a EUR 1.2 billion bond with a 12 year tenure and a EUR 1.3 billion bond with a six year tenure. See section 5.2.1 Risk review-Risk management-Financial risk and financial risk management-liquidity risk management for more information about liquidity.

Gross interest bearing financial liabilities

Gross interest bearing financial liabilities were NOK 75.3 billion at year end 2008, compared with NOK 50.5 billion at the end of 2007. The increase of NOK 24.8 billion was mainly related to an increase in non-current financial liabilities by NOK 10.2 billion due to weakening of the NOK versus the USD (NOK 1.59). In addition, cash collateral on financial counter parties and commercial papers increased by NOK 7.3 billion and NOK 3.0 billion, respectively in 2008.

Gross non-current financial liabilities were NOK 50.5 billion at year end 2007, compared with NOK 54.8 billion at the end of 2006. The decrease was mainly due to the weakening of the USD in relation to NOK in 2007 and the repayment of long-term borrowings in 2007. For risk management purposes, currency swaps are used to ensure that StatoilHydro keeps long-term interest-bearing debt in USD. As a result, most of the group's non-current financial liabilities are exposed to changes in the USD/NOK exchange rate.

Net interest bearing financial liabilities amounted to NOK 46.0 billion at 31 December 2008, compared with NOK 25.5 billion at 31 December 2007. The increase was mainly related to an increase in gross financial liabilities, partly offset by an increase in cash equivalents and current financial investments of NOK 6.8 billion.

Net interest bearing financial liabilities amounted to NOK 25.5 billion as of 31 December 2007, compared with NOK 43.8 billion as of 31 December 2006. The decrease was mainly due to an increase of NOK 13.1 billion in liquid assets and a decrease NOK 4.8 billion in gross non-current liabilities, mainly due to the weakening of the USD in relation to NOK in 2007. (For a reconciliation of net non-current financial investments with gross non-current financial liabilities, see report section 4.3.3 Financial performance-Non-GAAP measures-Net debt to capital employed ratio for more information.)

The net debt to capital employed ratio, defined as net interest-bearing debt in relation to capital employed, was 17.5% as of 31 December 2008, compared with 12.4% as of 31 December 2007. The 5.1% increase was mainly related to an increase in net financial liabilities of NOK 20.5 billion, partly offset by an increase in cash equivalents and current financial investments of NOK 6.8 billion.

Our method of calculating the net debt to capital employed ratio includes certain adjustments, and it may therefore be considered to be a non-GAAP financial measure. The net debt to capital employed ratio without adjustments was 17.7% in 2008, compared with 13.9% in 2007. (See report section 4.3.3 Financial performance-Non-GAAP measures-Net debt to capital employed ratio for more information.)

The net debt to capital employed ratio was 12.4% as of 31 December 2007, compared with 20.5% as of 31 December 2006. The decrease in the net debt to capital employed ratio in 2007 was mainly related to a decrease in net debt and an increase in shareholders' equity.

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.

New long-term borrowings totalled NOK 2.6 billion in 2008 and NOK 1.7 billion in 2007. The repayment of long-term debt at 31 December 2008 was NOK 2.9 billion compared with NOK 2.9 billion at 31 December 2007.

The company's central finance function manages the funding, liability and liquidity activities at group level based on our adopted financial policies.

Cash, cash equivalents and current financial investments were NOK 28.4 billion as of 31 December 2008, compared to NOK 21.6 billion as of 31 December 2007. The increase of NOK 6.8 billion was mainly due to higher cash inflows from increased revenues in 2008 compared to 2007, partly offset by higher investments in 2008 compared to 2007. The average liquids price increased from USD 72 (NOK 423) per barrel in 2007 to USD 97 (NOK 548) per barrel in 2008.

Cash and cash equivalents were NOK 18.6 billion as of 31 December 2008, compared to NOK 18.3 billion as of 31 December 2007. Current financial investments, which are part of our cash management, amounted to NOK 9.7 billion as of 31 December 2008, compared to NOK 3.4 billion as of 31 December 2007.

4.2.1 Principal contractual obligations

The table summarises our principal contractual obligations and other commercial commitments as of 31 December 2008.

The table includes contractual obligations, but excludes derivatives and other hedging instruments as well as asset retirement obligations, which for the most part are expected to lead to cash disbursements more than five years into the future. Obligations payable by StatoilHydro to unconsolidated equity affiliates are included gross in the table. Where StatoilHydro includes both an ownership interest and the transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the transport commitments that exceed Statoil's ownership share. See also report section 5.2.2 Risk review - Risk management- Quantitative and qualitative disclosures about market risk for more information.

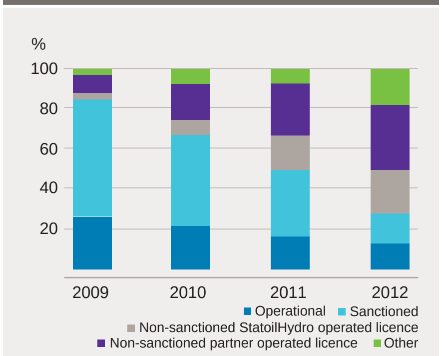
	As at 31 December, 2008 Payment due by period *				
Contractual obligations (in NOK billion)	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Total**
Undiscounted non-current financial liabilities	-	14.6	14.1	53.3	82.1
Minimum operating lease payments	16.1	22.5	10.8	4.0	53.3
Nominal minimum payments related to transport capacity, terminal capacity and similar commitments	7.8	16.1	13.5	41.7	79.1
Total contractual obligations	23.9	53.2	38.4	98.9	214.4

* ”Less than 1 year” represents 2009; ”1-3 years” represents 2010 and 2011, ”3-5 years” represents 2012 and 2013, while ”More than 5 years” includes amounts for 2014 and later periods.

Non-current financial liabilities in the table represents principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to note 20 - Non-current financial liabilities and note 25 - Leases to our Consolidated Financial Statements included this report.

Contractual obligations in respect of capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 47.4 billion as of 31 December 2008, of which payments of NOK 21.1 billion are due within one year.

ESTIMATED CAPEX FLEXIBILITY



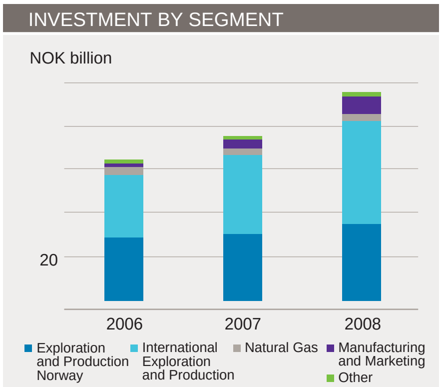
Over time we have increasing flexibility in terms of capital expenditure commitments. This flexibility is partly dependant on decision made by partners.

The group's projected pension benefit obligation was NOK 59.2 billion and the fair value of plan assets amounted to NOK 33.7 billion as of 31 December 2008. Actuarial gains and losses amounted to NOK 7.9 billion as of 31 December 2008 and are reported as part of the Statement of Recognised Income and Expense (SORIE) (equity). Company contributions are mainly related to employees in Norway. This payment may either be paid in cash or be deducted from the pension premium fund. On 31 December 2008, the pension premium fund amounts to NOK 4.5 billion. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. 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 of payroll tax). The expected company contribution related to 2009 is NOK 2.5 billion.

4.2.2 Investments

Our investments have increased due to more complex and challenging projects, inorganic growth and cost increases due to a tight supplier market.

INVESTMENT BY SEGMENT



Capital expenditure

Our capital expenditure in our four principal business segments in 2006 through 2008 is described below, including the allocation per segment as a percentage of gross investments. Capital expenditure is expected to amount to approximately NOK 95.3 billion in 2009.

Exploration expenditure

We experienced a step-up in exploration activities in during the period from 2006 to 2008. Exploration expenditure in 2008 amounted to NOK 17.8 billion, compared to NOK 14.2 billion in 2007 and NOK 13.4 billion in 2006. Exploration expenditure is expected to further increase to approximately NOK 18 billion in 2009. The group expects to participate in the drilling of approximately 70 wells in 2008. However, no guarantees can be given with regard to the number of wells drilled, the cost per well and the results of drilling. Uncertainty related to the results of past and future drilling will influence the amount of exploration expenditure capitalised and expensed. See report section 4.2.5 Financial performance-Liquidity and capital resources-Critical accounting judgements.

We use the "Successful efforts" method of accounting for oil and natural gas-producing activities. Expenditure on drilling and equipping exploratory wells is capitalised until it is clarified whether there are proved reserves. Expenditure on drilling exploratory wells that do not find proved reserves and geological, geophysical and other exploration expenditure is expensed. Unproved oil and gas properties are assessed quarterly; unsuccessful wells are expensed. Exploratory wells that have found reserves, but where classification of those reserves as proved depends on whether major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are either that firm plans exist for future drilling in the licence or that a development decision is planned in the near future.

Production cost per barrel is expected to increase as a result of tail-end production on mature fields on the NCS, PSA effects on production in international areas and continued pressure on costs in the industry.

This section describes our estimated capital expenditure for 2009 with respect to potential capital expenditure requirements for the principal investment opportunities available to us and other capital projects currently under consideration. The figure is based on StatoilHydro developing organically and it excludes possible expenditures related to acquisitions. Therefore, the expenditure estimates and descriptions with respect to investments in the segment descriptions below could differ materially from the actual expenditure. For more information on the various projects in each of the segments, see the respective report sub-sections described under sectoin 4 Financial performance.

Gross investments (NOK billion)	2008	2007	08-07 Change	2006	07-06 Change
	For the year ended 31 December				
E&P Norway	**34.9**	31.1	12%	29.2	6%
International E&P	**48.7**	36.2	35%	28.9	25%
Natural Gas	**2.0**	2.1	(6%)	3.2	(34%)
Manufacturing & Marketing	**8.5**	4.8	76%	2.5	93%
Other	**1.3**	0.8	73%	0.5	63%
Total gross investments	**95.4**	75.0	27%	64.3	17%

E&P Norway. A substantial proportion of our 2009 capital expenditure has been allocated to the ongoing development projects on Skarv, Ormen Lange, Gjøa, Vega, Morvin and Statfjord late life.

International E&P. We currently estimate that a substantial proportion of our 2009 capital expenditure will be allocated to the following ongoing and planned development projects: Peregrino in Brazil, Pazflor and PSVM in Angola, Marcellus Shale Gas and Tahiti in the USA , Leismer in Canada and Corrib in Ireland.

Natural Gas. We currently estimate that most of the 2009 capital expenditures will be spent on projects related to upgrading of the Kårstø processing plant in addition to the new Gjøa gas pipeline. The Gjøa gas pipeline ties the Gjøa field into Britain's existing Far North Liquids and Associated Gas System (Flags), which runs to St. Fergus in Scotland.

Manufacturing & Marketing. We are focusing our capital expenditure on upgrading our refineries to increase robustness and flexibility, as well as developing extra heavy oil value chains based on E&P assets. In 2006, we received the final permit to build a combined heat and power plant (CHP plant) at Mongstad. It will be built and operated by the Danish company Dong under a long-term lease agreement, in which StatoilHydro have an option to take ownership after 20 years, free of charge. We and our partners at Mongstad and on Troll will invest NOK 3.3 billion in refinery modifications and a gas pipeline from Kollsnes to Mongstad in connection with the CHP plant. In addition to the CHP project, the main focus at Mongstad in the next three years will be a coke safety unit, automation upgrade and improvements to infrastructure. At Kalundborg the main focus is infrastructure improvements.

As illustrated in section 4.2.1 Financial performance-Liquidity and capital resources-Principal contractual obligations, we have committed to certain investments in the future. The proportion of estimated investments that we have also committed to as of year end 2008 is declining with the time horizon. The farther into the future, the more flexibility we have in committing to the expenditure. This flexibility is partly dependent on what our partners in joint ventures agree to commit to.

Finally, we may alter the amount, timing or segmental or project allocation of our capital expenditure in anticipation or as a result of a number of factors outside our control including, but not limited to:

- exploration and appraisal results, such as favourable or disappointing seismic data or appraisal wells;
- cost escalation, such as higher exploration, production, plant, pipeline or vessel construction costs;
- government approval of projects;
- government awards of new production licences;
- partner approvals;
- the development and availability of satisfactory transport infrastructure;
- the development of markets for our petroleum products and other products, including price trends;
- political, regulatory or tax regime risks;
- accidents such as rig blowouts or fires, and natural hazards;
- adverse weather conditions;
- environmental problems which could lead, for instance, to development restrictions, costs relating to regulatory compliance or the effects of petroleum discharges or spills; and
- acts of war, terrorism and sabotage.

4.2.3 Material contracts

On 18 December 2006, Statoil and Norsk Hydro ASA announced that they had agreed to a merger of Norsk Hydro's oil and energy activities with Statoil. The merger was completed on 1 October 2007 and Statoil changed its name to StatoilHydro ASA.

See report section 3.13 Operational review-Related party transactions and report section 6.4 Shareholder information-Major shareholders, for a description of certain agreements we have entered into with the Norwegian State.

The merger was implemented by means of a demerger transaction effected in accordance with Norwegian law whereby the assets, rights and obligations relating to Norsk Hydro's oil and energy activities and certain related assets were transferred to the merged company for a consideration in the form of shares of Statoil to be issued to the shareholders of Norsk Hydro. Shareholders of Norsk Hydro received 0.8622 shares of the merged company for each Norsk Hydro share that they owned and 0.8622 ADSs in Statoil for each Norsk Hydro ADS that they owned. Following completion of the merger, the Norwegian State owned 62.5% of our shares. The shareholding has since increased and as of 5 March 2009, the Norwegian State had a direct interest of 67% of our shares, and an indirect holding of 3.94% through the state pension fund (Folketrygdefondet), for a total of 70.94% interest.

In accordance with the terms of the merger plan, with effect from 1 January 2007, the merged company took over certain assets, rights and obligations related to Norsk Hydro's activities, including:

- all payment obligations relating to outstanding bonds of the Norsk Hydro group, totalling approximately NOK 19 billion as of 1 January 2007;
- all guarantee obligations relating to the Norsk Hydro assets transferred to the merged company, representing a guarantee liability of approximately NOK 20 billion as of 1 January 2007;
- the allocation of rights, assets and obligations (including environmental and pension liabilities) based on an allocation ratio determined in accordance with the merger plan;
- the inter-company demerger balance representing a loan or claim of such magnitude that the net interest-bearing debt of the Norsk Hydro assets transferred to the merged company was NOK 1 billion as of 1 January, 2007. The balance was settled in February 2009 and will not have a significant impact on the consolidated equity. (See note 31 to the financial statements for more information about the merger);
- the assumption of pension obligations relating to employees of the Norsk Hydro group transferred to the merged company and certain former and retired employees; and
- all historical and future rights and obligations with respect to taxation issues of the relevant Norsk Hydro activities from 1 January, 2007.

4.2.4 Impact of inflation

Price increases for raw materials and services necessary to the development and operation of oil and gas producing assets have affected our results in recent years.

In recent years, our results have been affected significantly by inflation in the cost of certain raw materials and services necessary for the development and operation of oil and gas producing assets. Meanwhile, other parts of our business are not exposed to similar cost pressures.

While some of the cost pressure relates to capitalised expenditures thus only affecting our annual profit through increased depreciation, certain elements of operating expenditures have also been affected by this inflation. See our analysis of profit and loss as well as applicable outlook sections in report section 4.1 Financial performance - Strong operational performance for details.

As measured by the general consumer price index, inflation in Norway for the years ending 31 December 2008, 2007 and 2006 was 2.1%, 0.9% and 2.6%, respectively.

4.2.5 Critical accounting judgements

Critical accounting judgements and key sources of estimation uncertainty

This section describes the critical judgements that the Group has made in the process of applying the accounting policies.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU). The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB). This means that we are required to make estimates and assumptions. We believe that, of the company's significant accounting policies (see note 2 - Significant accounting policies to our Consolidated Financial Statements included in this report), the following may involve a greater degree of judgement and complexity, which in turn could materially affect the net income if various assumptions were changed significantly.

Critical judgements in applying accounting policies
The following are the critical judgements, apart from those involving estimations (see below), that the Group has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
As described under Transactions with the Norwegian State (see note 2 - Significant accounting policies to our Consolidated Financial Statements included in this report), the Group markets and sells the Norwegian State's share of oil and gas production from the NCS. The Group includes the costs of purchase and proceeds from the sale of the SDFI oil production in its Cost of goods sold and Revenue, respectively. In making the judgement the Group considered the detailed criteria for the recognition of revenue from the sale of goods set out in IAS 18 Revenue, and assessed in particular by analogy whether the risk and reward of the ownership of the goods had been transferred from the SDFI to the Group.

As also described in note 2 - significant accounting policies to our Consolidated financial statements, the Group 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 the Group's financial statements. In making the judgement the Group 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 the Group.

Method of accounting applied for the Hydro Petroleum merger
As described under Basis of preparation (see note 2 - Significant accounting policies to our Consolidated Financial Statements included in this report), the merger between former Statoil ASA and Hydro Petroleum has been accounted for using the carrying amounts of the assets and liabilities. When making this judgement the Group 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. StatoilHydro concluded that such a reorganisation would be best presented using the carrying amounts of assets and liabilities, and restating all 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.

The group is exposed to a number of underlying economic factors, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, as well as financial instruments with fair value derived from changes in these factors, which affect the overall results. In addition, the results of the group are influenced by the level of production, which in the short term may be influenced by for instance maintenance. 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 in accordance with industry standards and governed by criteria established by regulations of the SEC. 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. An independent third party has evaluated StatoilHydro's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions. 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 in accordance with 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 adverse effect on operating income as a result of increased impairment charges.

Exploration and leasehold acquisition costs. The Group accounting policy is to capitalise the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. The Group also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgements on 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. The Group has significant investments in property, plant and equipment and intangibles. 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 the 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 on a quarterly basis or when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount. If, following evaluation, an exploratory well has not found proved reserves, the previously capitalised costs are tested for impairment. Exploratory wells that have found reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the licence, or a development decision is planned in the near future.

Estimating the recoverable amount involves complexity in estimating relevant future cash flows based on future assumptions which are 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, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Long-term assumptions for major 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 consolidated balance sheet, and indirectly, the period's net pension expense in the consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made on 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 material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the accounts.

Asset retirement obligations. The Group 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, the 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 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 and hedging activities. The Group recognises all derivatives on the balance sheet at fair value. Changes in fair value of derivatives are included in the statement of income. Loans subject to fair value hedge accounting are adjusted for the fair value impact of the hedged risk. This adjustment will offset the majority of the change in fair value of the corresponding derivative.

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 income statement.

Income tax. The Group annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon management's ability to properly apply at times very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

4.2.6 Off balance sheet arrangements

This section describes various agreements such as operational leases and transportation and processing capacity contracts that are not recognised in the balance sheet.

We have entered into various agreements, such as operational leases and transportation and processing capacity contracts that are not recognised in the balance sheet. See report section 4.2.1 Financial performance-Liquidity and capital resources-Principal contractual obligations for more information.

We are not party to any off-balance sheet arrangements such as the use of Variable Interest Entities.

The group is party to certain guarantees, commitments and contingencies that pursuant to IFRS are not necessarily recognised in the balance sheet as liabilities. See note 26 Other commitments and contingencies in the Consolidated Financial Statements in section 8 for more information.

4.3 Non-GAAP measures

Use and reconciliation of non-GAAP measures

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

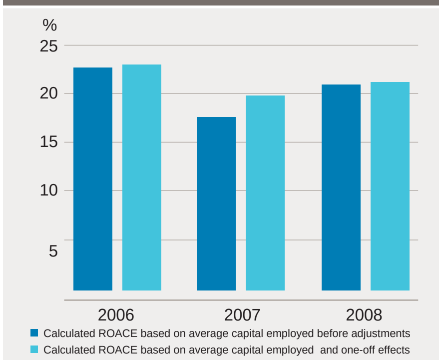
The following financial measures may be considered non-GAAP financial measures:

- Return on Average Capital Employed (ROACE).
- Normalised production cost per barrel.
- Net debt to capital employed ratio.

4.3.1 Return on capital employed (ROACE)

StatoilHydro uses ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt.

ROACE CALCULATION



StatoilHydro uses ROACE to measure the return on capital employed, regardless of whether the financing is through equity or debt. In the company's view, this measure provides useful information, both for the company and for investors, regarding performance during the period under evaluation. We make regular use of this measure to evaluate our operations. Our use of ROACE should not be viewed as an alternative to income before financial items, income taxes and minority interest, or to net income, which are measures calculated in accordance with generally accepted accounting principles or ratios based on these figures.

ROACE was 21.3% in 2008, compared with 17.9% in 2007 and 22.9% in 2006. The increase from last year was mainly due to higher prices on both liquids and natural gas, an increase of volumes of natural gas sold and a increase in net financial loss.

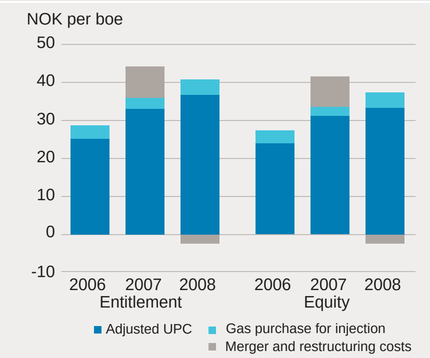
Adjusted for the effects of restructuring costs and other costs arising from the merger, ROACE was 21.1% in 2008, compared with 19.9% in 2007 and 22.9% in 2006. ROACE is defined as a non-GAAP financial measure.

	Twelve months ended 31 December		
Calculation of numerator and denominator used in ROACE calculation (in NOK million, except percentages)	**2008**	**2007**	**2006**
Net income for the last 12 months	**43,270**	44,641	51,847
After-tax net financial items for the last 12 months	**6,415**	(7,157)	(5,072)
Net income adjusted for financial items after tax (A1)	**49,685**	37,484	46,775
Adjustment for restructuring costs and other costs arising from the merger	**(354)**	4,212	0
Net income adjusted for restructuring costs and other costs arising from the merger (A2)	**49,331**	41,696	46,775
Calculated average capital employed:			
Average capital employed before adjustments (B1)	**236,405**	211,806	206,100
Average capital employed (B2)	**233,273**	208,857	204,408
Calculated ROACE:			
Calculated ROACE based on average capital employed before adjustments (A1/B1)	**21.0%**	17.7%	22.7%
Calculated ROACE based on average capital employed (A1/B2)	**21.3%**	17.9%	22.9%
Calculated ROACE based on average capital employed and one-off effects (A2/B2)	**21.1%**	19.9%	22.9%

4.3.2 Normalised production cost

Normalised production cost in NOK per boe is used to evaluate the underlying development in production costs.

PRODUCTION COST SUMMARY



Normalised production cost in NOK per boe is used to evaluate the underlying development in production costs. StatoilHydro's international production costs are mainly incurred in USD. In order to exclude currency effects and to reflect the change in the underlying production cost, the USD/NOK exchange rate is held constant at 6.00 when calculating normalised production cost. The normalised figures for the relevant previous periods have been restated in order to facilitate comparison.

	Entitlement production Twelve months ended 31 December			Equity production Twelve months ended 31 December		
(in NOK per boe)	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
Calculated production cost	**38.1**	44.1	28.4	**34.6**	41.4	27.3
Calculated production cost, excluding restructuring cost from the merger	**40.6**	35.7	na	**36.9**	33.5	na
Calculated production cost, excluding restructuring and gas injection cost	**36.7**	33.2	25.1	**33.3**	31.2	24.1
Total liquids and gas production (mboe per day)	**1,751**	1,724	1,708	**1,925**	1,839	1,780

Entitlement volumes used in the calculation of the normalised production cost per boe have been adjusted for PSA effects. Higher oil price levels affect the production entitlement volumes negatively, and hence the production unit cost.

Entitlement volumes are highly affected by production sharing agreements (PSA effects). On average, the equity volumes exceeded entitlement volumes by 174 mboe per day in 2008, 115 mboe per day in 2007 and 70 mboe per day in 2006. With the same cost basis but higher volumes, cost per barrel of equity volumes will always be lower than cost per barrel of entitlement volumes. Based on equity volumes average production cost (not normalised) was NOK 34.6 per boe in 2008, compared to NOK 41.4 per boe in 2007 and NOK 27.3 per boe in 2006.

Production cost per boe	2008	Twelve months ended 31 December 2007	2006
Total production costs last 12 months (in NOK million)	**24,184**	27,776	17,675
Produced volumes last 12 months (million boe)	**635**	629	623
Average USDNOK exchange rate last 12 months	**5.64**	5.86	6.41
Production cost (USD/boe)	**6.83**	7.70	4.44
Calculated production cost (NOK/boe)	**38.1**	44.1	28.4
Normalisation of production cost per boe:			
Production costs last 12 months International E&P (in USD million)	**759**	662	498
Normalised exchange rate (USDNOK)	**6.00**	6.00	6.00
Production costs last 12 months International E&P normalised at USDNOK 6.00	**4,552**	3,972	2,987
Production costs last 12 months E&P Norway (in NOK million)	**19,947**	23,919	14,488
Total production costs last 12 months in NOK million (normalised)	**24,499**	27,891	17,475
Production cost (NOK/boe) normalised at USDNOK 6.00 [8]	**38.6**	44.3	28.1

4.3.3 Net debt to capital employed ratio

The calculated net debt to capital employed ratio is viewed by the company as providing a more complete picture of the group's current debt situation than gross interest-bearing debt.

The calculated net debt to capital employed ratio is viewed by the company as providing a more complete picture of the group's current debt situation than gross interest-bearing debt. The calculation uses balance sheet items relating to total debt and adjusts for cash, cash equivalents and short-term investments. Certain adjustments are made since different legal entities in the group lend to projects and others borrow from banks, project financing through an external bank or similar institution will not be netted in the balance sheet and will over-report the debt stated in the balance sheet compared to the underlying exposure in the group. Similarly, certain net interest-bearing debt incurred from activities pursuant to the Marketing Instruction of the Norwegian State is off-set against receivables on the SDFI.

The net interest-bearing debt adjusted for these two items is included in the average capital employed, which is also used in the calculation of ROACE.

The table below reconciles net interest-bearing debt, capital employed and net debt to capital employed ratio with the most directly comparable financial measure or measures calculated in accordance with GAAP.

	Twelve months ended 31 December		
Calculation of capital employed and net debt to capital employed ratio (in NOK billion)	**2008**	**2007**	**2006**
Total shareholders' equity	**214.1**	177.3	167.8
Minority interest	**2.0**	1.8	1.6
Total equity and minority interest (A)	**216.1**	179.1	169.4
Short-term debt	**20.7**	6.2	5.6
Long-term debt	**54.6**	44.4	49.2
Gross interest-bearing debt	**75.3**	50.5	54.8
Cash and cash equivalents	**18.6**	18.3	7.5
Current financial investments	**9.7**	3.4	1.0
Cash and cash equivalents and current financial investments	**28.4**	21.6	8.6
Net debt before adjustments (B1)	**46.9**	28.9	46.2
Other interest-bearing elements	**1.9**	0.0	0.0
Marketing instruction adjustment	**(1.7)**	(1.4)	0.0
Adjustment for project loan	**(1.1)**	(2.0)	(2.4)
Net interest-bearing debt (B2)	**46.0**	25.5	43.8
«Normalisation for cash-build up before tax payment (50% of tax payment)»	**0.0**	0.0	0.0
Net interest-bearing debt (B3)	**46.0**	25.5	43.8
Calculation of capital employed:			
Capital employed before adjustments to net interest-bearing debt (A+B1)	**264.8**	208.0	215.6
Capital employed before normalisation for cash build-up for tax payment (A+B2)	**262.0**	204.5	213.2
Capital employed (A+B3)	**262.0**	204.5	213.2
Calculated net debt to capital employed:			
Net debt to capital employed before adjustments (B1/(A+B1))	**17.7%**	13.9%	21.4%
Net debt to capital employed before normalisation for tax payment (B2/(A+B2)	**17.5%**	12.4%	20.5%
Net debt to capital employed (B3/(A+B3))	**17.5%**	12.4%	20.5%

4.4 Accounting Standards (IFRS)

In accordance with Norwegian and European Union (EU) regulations, StatoilHydro has prepared its first set of consolidated financial statements for 2007 in accordance with the International Financial Reporting Standards (IFRS) adopted by the EU.

The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

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

Change in parent company functional currency
StatoilHydro reports with the US dollar as the functional currency in the parent company while the group has retained NOK as the reporting currency, effective in the first quarter of 2009.

Everything else being equal, this is expected to reduce the volatility in net income caused by fluctuations in the USD/NOK rate. Due to the difference between functional currency and reporting currency, certain currency valuation effects will still be recorded, but they will now be recorded directly to equity under other comprehensive income.

Specifically, USD denominated assets and liabilities held by the parent company that to date have given rise to material currency gains and losses will no longer give rise to such effects. An example of this has been the recent currency losses on USD denominated loans.

Assets and liabilities held by the parent company and denominated in other currencies than USD, e.g. NOK, will however give rise to new currency gains and losses. An example of this will be the NOK denominated tax liabilities.

The change in functional currency is thus expected to reduce volatility in net income but add volatility in other comprehensive income. The change is not expected to have a material impact on the ability to pay dividends. Prior period financial statements are not required to be restated.

5 Risk review

5.1 Risk factors

5.1.1 Risks related to our business

A substantial or extended decline in oil or natural gas prices would have a material adverse effect on us.
Historically, prices of oil and natural gas have fluctuated greatly in response to changes in many factors. We do not and will not have control over the factors affecting the prices of oil and natural gas. These factors include:

- global and regional economic and political developments in resource-producing regions, particularly in the Middle East and South America
- global and regional supply and demand
- the ability of the Organization of the Petroleum Exporting Countries (OPEC) and other producing nations to influence global production levels and prices
- prices of alternative fuels which affect our realised prices under our long-term gas sales contracts
- Norwegian and foreign governmental regulations and actions
- global economic conditions
- war or other international conflicts
- changes in population growth and consumer preferences
- the price and availability of new technology, and
- weather conditions.

It is impossible to predict future price movements for oil and natural gas with certainty. An extended decline in oil and natural gas prices will adversely affect our business, the results of our operations and our financial condition, our liquidity and our ability to finance planned capital expenditure. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators could lead to further reviews for impairment of the group's oil and natural gas properties. Such reviews would reflect management's view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on our results of operations in the period in which it occurs. Rapid material and/or sustained reductions in oil, gas and product prices can impact the validity of the assumptions on which strategic decisions are based and can impact the economic viability of projects planned or in development. For an analysis of the impact on net operating income of changes in oil and gas prices, see section 5.2 Risk review-Risk Management.

The global financial and credit crisis may have impacts on our liquidity and financial condition that we currently cannot predict.
The credit crisis and related turmoil in the global financial systems may have a material impact on our liquidity and our financial condition, and we may ultimately face major challenges if conditions in the financial markets do not improve. If the capital and credit markets continue to experience volatility and the availability of funds remains limited, we may incur increased costs associated with debt financings and our ability to access the capital markets or borrow money may become restricted at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions, on our ability to fund our operations and capital expenditures in the future and on our growth rate and shareholder returns. Decreases in the funded levels of our pension plans may also increase our pension funding requirements. In this context, changes in our debt rating could have a material adverse effect on our interest costs and financing sources. Our debt rating can be materially influenced by a number of factors including, but not limited to, acquisitions, investment decisions, and capital management activities.

The current economic situation could lead to reduced demand for oil and natural gas, or further reductions in the prices of oil and natural gas, or both, which would have a negative impact on our financial position, results of operations and cash flows. Governments will be facing greater pressure on public finances, leading to risk of increased taxation. These factors may also lead to intensified competition for market share and available margin, with consequential potential adverse effects on volumes. The financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. While the ultimate outcome and impact of the current financial crisis cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial condition.

We may not be able to realise the full benefits of the merger.
It may not be possible to realise the full benefits that we anticipated to result from the merger with Hydro Petroleum, which was completed in October 2007, or we may not realise these benefits within the expected timeframe (2009 to 2010). The benefits of the merger may be offset by operating losses relating to changes in commodity prices or in oil and gas industry conditions, risks and uncertainties relating to our exploration and production prospects, an increase in operating or other costs, unanticipated difficulties and restructuring and other costs related to the merger, the impact of competition and other risk factors relating to the industry.

Drilling involves numerous risks, including the risk that we will encounter no commercially productive oil or natural gas reservoirs, which could materially adversely affect our results.
We are exploring or considering exploring in various geographical areas, including resource provinces such as the Norwegian Sea, the Barents Sea, the Deepwater US Gulf of Mexico, the Arctic, onshore Algeria and Libya, as well as offshore Alaska, Angola, Brazil and Venezuela, where environmental conditions are challenging and costs can be high. In addition, our use of advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. The cost of drilling, completing and operating wells is often uncertain. As a result, we may incur cost overruns or may be required to curtail, delay or cancel drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages of or delays in the availability of drilling rigs and the delivery of equipment. For example, we have entered into long-term leases for drilling rigs which may turn out not to be required for the originally intended operations, and we cannot be certain that these rigs will be re-employed or at what rates they will be re-employed. Fluctuations in the market for leases of drilling rigs will also have an impact on the rates we can charge in re-employing these rigs. Our overall drilling activity or drilling activity within a particular project area may be unsuccessful. Such failure will have a material adverse effect on the results of our operations and financial condition.

If we fail to acquire or find and develop additional reserves, our reserves and production will decline materially from their current levels.
The majority of our proved reserves are on the Norwegian Continental Shelf (NCS), a maturing resource province. Unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves, our proved reserves will decline as reserves are produced. Successful execution of our group strategy depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves. In addition, the volume of production from oil and natural gas properties generally declines as reserves are depleted. For example, some of our major fields, such as Gullfaks, are dependent on satellite fields to maintain production and, unless efforts to improve the development of satellite fields are successful, production will gradually decline.

In a number of resource rich countries, national oil companies control a significant portion of oil and gas reserves that remain to be developed. To the extent that national oil companies choose to develop their oil and gas resources without the participation of international oil companies or that we are unable to develop partnerships with national oil companies, our ability to find and acquire or develop additional reserves will be limited.

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

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

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

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

These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licences, and they may be able to invest more in developing technology than our financial or human resources permit. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry. For more information on the competitive environment, see section 3.11 Operational Review-Competition.

We face challenges in executing our strategic objective of successfully exploiting growth opportunities.
An important element of our strategy is to continue to pursue attractive growth opportunities available to us, both in enhancing and repositioning our asset portfolio and expanding into new markets. The opportunities that we are actively pursuing may involve acquisitions of businesses or properties that complement or expand our existing portfolio, and the challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally.
Our ability to implement this strategy successfully will depend on a variety of factors, including our ability to:

- identify acceptable opportunities
- negotiate favourable terms

- develop the performance of new market opportunities or acquired properties or businesses promptly and profitably
- integrate acquired properties or businesses into our operations
- arrange financing, if necessary, and
- comply with legal regulations.

As we pursue business opportunities in new and existing markets, we anticipate significant investments and costs in connection with the development of such opportunities. We may incur or assume unanticipated liabilities, losses or costs associated with assets or businesses acquired. Any failure by us to pursue and exploit new business opportunities successfully could result in financial losses and could inhibit growth.

If we are successful in the pursuit of our strategy and the making of such acquisitions, and no assurances can be given that we will be, our ability to achieve our financial, capital expenditure and production forecasts may be materially affected. Any such new projects we acquire will require additional capital expenditure and will increase the cost of our discoveries and development. These projects may also have different risk profiles than our existing portfolio. These and other effects of such acquisitions could result in us having to revise either or both of our forecasts with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from our day-to-day operations to the integration of acquired operations or properties, including those operations and properties subject to the final phases of integration after the merger with Hydro Petroleum. We may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to us, if at all, and it may, in the case of equity, be dilutive to our earnings per share.

Our development projects involve many uncertainties and operating risks that can prevent us from realising profits and cause substantial losses.
Our development projects may be delayed or unsuccessful for many reasons, including cost overruns, lower oil and gas prices, equipment shortages, mechanical and technical difficulties and industrial action. These projects will also often require the use of new and advanced technologies, which may be expensive to develop, purchase and implement, and may not function as expected. In addition, some of our development projects will be located in deepwater or other hostile environments, such as the Gulf of Mexico and the Barents Sea, or produced from challenging reservoirs, which can exacerbate such problems. There is a risk that development projects that we undertake may suffer from such problems.

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

We face challenges in the renewable energy sector.
Although energy production from renewables is at this time modest in most countries, wind power, solar energy and biofuels are developing into significant industries. We cannot predict the demand for renewables. We believe that technological innovation and the integration of trend-breaking technologies such as biotechnology and other new ideas is key to advancing in the renewable energy sector and meeting a profitable, sustainable, low-carbon energy future. Some of our competitors may be able to invest more in developing technology in the renewable energy sector than we do. Our performance in the renewable energy sector could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry. In addition, projects in renewable energy deal with emerging technologies, evolving manufacturing techniques and/or cutting edge implementation. Little precedence exists for incorporating certain renewable aspects into new or existing projects.

We may not be able to produce some of our oil and gas economically due to the lack of necessary transportation infrastructure when a field is in a remote location.
Our ability to exploit economically any discovered petroleum resources beyond our proved reserves will be dependent, among other factors, on the availability of the necessary infrastructure to transport oil and gas to potential buyers at a commercially acceptable price. Oil is usually transported by tankers to refineries, and natural gas is usually transported by pipeline to processing plants and end-users. We may not be successful in our efforts to secure transportation and markets for all of our potential production.

Some of our international interests are located in politically, economically and socially unstable areas, which could disrupt our operations.
We have assets located in unstable regions around the world. For example, the states bordering the Caspian Sea dispute ownership and distribution of proceeds from the Caspian's seabed and subsoil resources. Our activities in the Persian Gulf may be subject to disruption due, for example, to war and terrorism. Other countries, such as Venezuela, Nigeria and Angola, where we also have operations, have experienced expropriation or nationalisation of property, civil strife, strikes, acts of war, guerrilla activities and insurrections. The occurrence of incidents related to political, economic or social instability could disrupt our operations in any of these regions, causing a decline in production that could have a material adverse effect on our results of operations or financial condition.

Our operations are subject to political and legal factors in the countries in which we operate.
We have assets in a number of countries with emerging or transitioning economies, which lack well-established and reliable legal systems, where the enforcement of contractual rights is uncertain or where the governmental and regulatory framework is subject to unexpected change. Our exploration and production activities in these countries are often undertaken together with national oil companies and are subject to a significant degree of state control. In recent years, governments and national oil companies in some regions have begun to exercise greater authority and impose more stringent conditions on companies pursuing exploration and production activities, which is a trend we expect to continue. Intervention by governments in such countries can take a wide variety of forms, including:

- restrictions on exploration, production, imports and exports,
- the award or denial of exploration and production interests,
- the imposition of specific seismic and/or drilling obligations,
- price controls,
- tax or royalty increases, including retroactive claims,
- nationalisation or expropriation of our assets,
- unilateral cancellation or modification of our licence or contract rights,
- the renegotiation of contracts,
- payment delays, and
- currency exchange restrictions or currency devaluation.

The likelihood of these occurrences and their overall effect on us vary greatly from country to country and are not predictable. If such risks materialise, they could cause us to incur material costs or cause our production to decrease, potentially having a material adverse effect on our operations or financial condition.

Our activities in certain countries could lead to US sanctions.
In October 2002, we signed a participation agreement with Petropars of Iran, pursuant to which we assumed the operatorship for the offshore part of phases 6-7-8 of the South Pars gas development project in the Persian Gulf. By the end of 2008, we had invested a total of USD 225.3 million in South Pars. In addition, as a result of the merger with Norsk Hydro's oil and gas business, StatoilHydro now owns a 75% interest in the Anaran Block in Iran, which was acquired by Norsk Hydro in 2000. Following the commerciality declaration of the Azar discovery in the Anaran Block in August 2006, we agreed to conduct negotiations with the National Iranian Oil Company for a Master Development Plan and a Development Service Contract. The Anaran Block is currently in the exploration phase.By the end of 2008, StatoilHydro had zero book value of investments, after impairment related to the Anaran project. Also, as a result of the merger, StatoilHydro now owns a 100% interest in the Khorramabad Exploration Block, where StatoilHydro is the operator. In September 2006, Norsk Hydro signed the Khorramabad Exploration and Development Contract with the National Iranian Oil Company, with a total commitment of USD 49.5 million over four years related to seismic survey and other exploration activities. We completed the gathering of seismic data in the Khorramabad Exploration Block in the fourth quarter of 2008. The scope and timing of further work programmes on the Khorramabad Exploration Block is now being evaluated. See section 3.2.6.5.1 Operational review-International E&P - The Middle East and Asia - Iran.

In June 2008 the US Department of State announced that it would review StatoilHydro's activities to determine whether they breached the Iran Sanctions Act of 1996 (ISA). In testimony to the House Foreign Affairs Committee on 9 July 2008, Undersecretary of State for Political Affairs William Burns suggested that the Norwegian company's investment in South Pars might fall within the purview of the ISA. The ISA requires the President of the US to sanction companies with investments of USD 20 million or more in Iran's energy sector. Such sanctions could include denial of US bank loans and restrictions on the importation of goods produced by the sanctioned company. We cannot predict interpretations of or the implementation policy of the US Government under ISA with respect to our current or future activities in Iran or other areas. It is possible that the United States may determine that these investments in Iran or other activities will constitute activity covered by ISA and will subject us to sanctions.

Iran and certain other countries, including Cuba, have been identified by the US State Department as state sponsors of terrorism. Our activities in Cuba consist of a 30% interest in six deepwater exploration blocks acquired from Repsol-YPF in 2006. At the end of 2008, we had invested USD 13.7 million in these projects. These activities are not material to our business, financial condition or results of operations, as the total amount invested in these operations in 2008 represented less than 0.02 % of our total assets as of 31 December, 2008.

We are aware of initiatives by certain US states and US institutional investors, such as pension funds, to adopt or consider adopting laws, regulations or policies requiring divestment from, or reporting of interests in, companies that do business with countries designated as state sponsors of terrorism. These policies could adversely impact investment by certain investors in our securities.

We are exposed to potentially adverse changes in the tax regimes of each jurisdiction in which we operate.
We operate in 40 countries around the world, and any of these countries could modify its tax laws in ways that would adversely affect us. Most of our operations are subject to changes in tax regimes in a similar manner to other companies in our industry. In addition, in the long-term, the marginal tax rate in the oil and gas industry tends to change with the price of crude oil. Significant changes in the tax regimes of countries in which we operate could have a material adverse affect on our liquidity and the results of our operations.

We are exposed to potential losses and could be seriously harmed by natural disasters, operational catastrophes or security breaches.
Exploration for, the production of, and the transportation of oil and natural gas is hazardous, and natural disasters, operator error or other occurrences can result in oil spills, gas leaks, loss of containment of hazardous materials exposed to blowouts, cratering, fires, equipment failure and loss of well control. Failure to manage these risks could result in injury or loss of life, damage or destruction of wells and production facilities pipelines and other property and damage to the environment. All modes of transportation of hydrocarbons contain inherent risks. A loss of contaminant of hydrocarbons and other hazardous materials could occur during transportation by road, rail, sea or pipeline. This is a significant risk due to the potential impact of a release on the environment and people given the high volumes involved.

Offshore operations are subject to marine perils, including severe storms and other adverse weather conditions, vessel collisions, and governmental regulations, as well as interruptions or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events would significantly reduce our revenues or increase our costs and have a material adverse effect on our operations or financial condition.

We are exposed to risks regarding safety and security of our operations. Inability to provide safe environments for our workforce and the public could lead to injuries or loss of life and could result in regulation action, legal liability and damage to our reputation. Security threats require continuous oversight and control. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems could severely disrupt businesses and operations and could cause harm to people.

Our crisis management systems may be ineffective
We have developed contingency plans to continue or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed timeframe could prolong impact of any disruption and could severely affect business and operations. Likewise, we have crisis management plans and capability to deal with emergencies at every level of our operations. If we do not respond or are not perceived to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

The crude oil and natural gas reserve data in this Annual Report on Form 20-F are only estimates, and our future production, revenues and expenditures with respect to our reserves may differ materially from these estimates.
The reliability of proved reserve estimates depends on:

- the quality and quantity of our geological, technical and economic data;
- whether the prevailing tax rules and other government regulations, contracts, and oil, gas and other prices will remain the same as on the date estimates are made;
- the production performance of our reservoirs; and
- extensive engineering judgments.

Many of the factors, assumptions and variables involved in estimating reserves are beyond our control and may prove to be incorrect over time. Results of drilling, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserve data. In addition, fluctuations in oil and gas prices will have an impact on our proved reserves relating to fields governed by Production Sharing Agreements, or PSAs, since part of our entitlement under PSAs relates to the recovery of development costs. Any downward adjustment could lead to lower future production and thus adversely affect our financial condition, future prospects and market value.

We face foreign exchange risks that could adversely affect the results of our operations.
Our business faces foreign exchange risks because a large percentage of our revenues and cash receipts are denominated in US dollars, while sales of refined products may be in a variety of currencies. Fluctuations between the US dollar and other currencies may adversely affect our business and can give rise to foreign exchange exposures with a consequent impact on underlying costs and revenues. See note 28 - Financial risk management-Market risk to the Consolidated Financial Statements in this report or Section 5.2.1. Risk review-Risk management-financial risk and financial risk management below for more information regarding risk management.

We are exposed to risks relating to trading and supply activities.
StatoilHydro is engaged in substantial trading and commercial activities in the physical markets and it also uses financial instruments such as futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage price volatility. We also use financial instruments to manage foreign exchange and interest rate risk.

Although StatoilHydro believes it has established appropriate risk management procedures, trading activities involve elements of forecasting and StatoilHydro bears the risk of market movements - the risk of significant losses if prices develop contrary to expectations - and the risk of default by counterparties. See note 28 - Financial risk management-Market risk to the Consolidated Financial Statements in this report or Section 5.2.1. Risk review-Risk management-financial risk and financial risk management below for more information regarding risk management. Any of these risks could have an adverse effect on the results of our operations and financial condition.

Our investments, business, profitability and results of operations may be adversely affected as a result of the difficult conditions in the financial markets.

StatoilHydro's ability to access or continue to access domestic and international capital markets and lenders to the extent sufficient to meet its funding needs, including the refinancing of outstanding debt falling due, may be adversely affected by a number of factors, including Norwegian and international economic conditions and the state of the Norwegian financial system.

Since the second half of 2007, disruption in the global credit markets, coupled with the repricing of credit risk and the deterioration of the housing markets in the United States, the United Kingdom and elsewhere, has created increasingly difficult conditions in the financial markets. Among the sectors of the global credit markets that are experiencing particular difficulty due to the current crisis are the markets associated with subprime mortgage backed securities, asset backed securities, collateralised debt obligations, leveraged finance and complex structured securities. These conditions have resulted in historically high volatility, less liquidity or no liquidity, widening of credit spreads and a lack of price transparency in certain markets.

Most recently, these conditions have resulted in the failures of a number of financial institutions in the United States and Europe and unprecedented action by governmental authorities and central banks around the world. It is difficult to predict how long these conditions will last and how StatoilHydro's business, projects and markets will be affected. These conditions may be exacerbated by persisting volatility in the financial sector and the capital markets, or concerns about, or a default by, one or more institutions, which could lead to significant market wide liquidity problems, losses or defaults by other institutions. Accordingly, these conditions could adversely affect StatoilHydro's business, financial condition or results of operations in future periods. In addition, StatoilHydro may become subject to litigation and regulatory or governmental scrutiny, or may be subject to changes in applicable regulatory regimes that may be materially adverse. Furthermore, it is not possible to predict what structural and/or regulatory changes may result from the current market conditions or whether such changes may be materially adverse to StatoilHydro and its prospects.

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

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

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

5.1.2 Risks related to the regulatory regime

Competition is expected to increase in the European gas market, currently our main market for gas sales, as a result of European Union (EU) directives and the general liberalisation of European gas markets which could adversely affect our ability to expand or even maintain our current market position or result in a reduction in prices in our gas sales contracts.

Fundamental changes continue to take place in the organisation and operation of the European gas market with the objective of opening national markets to competition and integrating them into a single market for natural gas. This process started with the EU Gas Directive, which became effective in August 2000.

The European Commission launched a new initiative to further develop the EU gas market in September of 2007 and it is expected that this package of legislative measures will be approved by May 2009. The impact of such measures depends on the final version implemented but it is expected to create stronger national regulators, a pan European regulatory agency and promote the improved functioning of the gas market in Europe.

Another EU initiative likely to impact the market for gas involves the environmental package implemented in December 2008 which strengthens and extends the Emissions Trading Scheme and creates national targets for renewable energy. Both will have positive and negative impacts on the competitive position of natural gas as a fuel.

The third focus area of EU energy policy is supply security and this has lead to an increased focus on projects diversifying gas supplies to the EU. As a result, the Caspian region now receives increased attention from the EU where StatoilHydro participates in the Shah Deniz field. Solutions to bring Caspian gas to Europe are receiving political support from the EU in an attempt to resolve the complex transportation issue in the region.

Most of our gas is sold under long-term gas contracts to customers in the EU, a gas market that will continue to be affected by changes in EU regulations and the implementation of such regulations in EU member states. As a result of the directives, our ability to expand or even maintain our current market position could be materially adversely affected and quantities sold under our gas sales contracts may be subject to a material reduction in gas prices.

We may incur material costs in connection with complying with, or as a result of, health, safety and environmental laws and regulations.
Compliance with environmental laws and regulations in Norway and abroad could materially increase our costs. We incur, and expect to continue to incur, substantial capital and operating costs relating to compliance with increasingly complex laws and regulations covering the protection of the environment and human health and safety, including:

- costs of reducing certain types of emissions to air and discharges to the sea
- remediation of environmental contamination at various owned and previously-owned facilities and at third party sites where our products or waste have been handled or disposed
- compensation of persons claiming damages caused by our activities or accidents, and
- costs in connection with the decommissioning of drilling platforms and other facilities.

The Norwegian Petroleum Safety Authority (PSA) was established on 1 January 2004, with regulatory responsibility for safety, emergency preparedness and the working environment for all petroleum-related activities. See section 3.10 Operational review-Regulation.

In our capacity as holder of licences on the NCS under the Norwegian Petroleum Act of 29 November 1996, we are subject to statutory strict liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licences. This means that anyone who suffers losses or damage as a result of pollution caused by operations in any of our NCS licence areas can claim compensation from us without needing to demonstrate that the damage is due to any fault on our part.

Whether in Norway or abroad, new laws and regulations, the imposition of tougher requirements on licences, increasingly strict enforcement of or new interpretations of existing laws and regulations, or the discovery of previously unknown contamination may require future expenditure to:

- modify operations
- install pollution control equipment
- implement additional safety measures
- perform site clean-ups, or
- curtail or cease certain operations.

In particular, we may be required to incur significant costs to comply with the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol, and other pending EU laws and directives. In addition, increasingly strict environmental requirements, including those relating to petrol sulphur levels and diesel quality, affect product specifications and operational practices. Future expenditure to meet such specifications could have a material adverse effect on our operations or financial condition.

Compliance with laws, regulations and obligations relating to climate change and other environmental regulations could result in substantial capital expenditure, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted. Many of our mature fields are producing increasing quantities of water with oil and gas. Our ability to dispose of this water in environmentally acceptable ways may have an impact on our oil and gas production.

If we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment, we could fail to live up to our aspirations of no or minimal damage to the environment and contributing to human progress.

Political and economic policies of the Norwegian State could affect our business.
The Norwegian State plays an active role in the management of NCS hydrocarbon resources. In addition to its direct participation in petroleum activities through the State's Direct Financial Interest (SDFI) and its indirect impact through tax and environmental laws and regulations, the Norwegian State awards licences for reconnaissance, production and transportation, and it approves, among other things, exploration and development projects, gas sales contracts and applications for (gas) production rates for individual fields. The Norwegian State may, if important public interests are at stake, also instruct us and other oil companies to reduce the production of petroleum. Furthermore, in the production licences in which the SDFI holds an interest, the Norwegian State retains the ability to direct petroleum licencees' actions in certain circumstances.

If the Norwegian State were to take additional action pursuant to its extensive powers over activities on the NCS or to change laws, regulations, policies or practices relating to the oil and gas industry, our NCS exploration, development and production activities and results of our operations could be materially and adversely affected. For more information about the Norwegian State's regulatory powers, see section 3.10 Operational review-Regulation.

5.1.3 Risks related to ownership by Norwegian state

The interests of our majority shareholder, the Norwegian State, may not always be aligned with the interests of our other shareholders, and this may affect our decisions relating to the NCS.

The Norwegian Parliament, known as the Storting, and the Norwegian State have resolved that the Norwegian State's shares in StatoilHydro and the SDFI's interest in NCS licences must be managed in accordance with a coordinated ownership strategy for the Norwegian State's oil and gas interests. Under this strategy, the Norwegian State has required us to continue to market the Norwegian State's oil and gas together with our own as a single economic unit.

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

The Norwegian State held 66.89% of our ordinary shares as of 5 March 2009 and held an additional 3.94% through Folketrygdfondet, totaling to 70.83%. A two-thirds majority is required to determine matters submitted for a vote of shareholders, and the Norwegian state effectively has the power to influence the outcome of any shareholder vote due to the size of its percentage ownership in our shares, including amending our articles of association and electing all non-employee members of the corporate assembly. The employees are entitled to be represented by up to one-third of the members of the board of directors and one-third of the corporate assembly.

The corporate assembly is responsible for electing our board of directors. It also makes recommendations to the general meeting concerning the board of directors' proposals relating to the company's annual accounts, balance sheet, allocation of profits and coverage of loss. The interests of the Norwegian State in deciding these and other matters and the factors it considers in exercising its votes, especially under the coordinated ownership strategy for the SDFI and our shares held by the Norwegian State, could be different from the interests of our other shareholders. Accordingly, when making commercial decisions relating to the NCS, we have to take the Norwegian State's coordinated ownership strategy into account, and we may not be able to fully pursue our own commercial interests, including those relating to our strategy for the development, production and marketing of oil and gas.

If the Norwegian State's coordinated ownership strategy is not implemented and pursued in the future, then our mandate to continue to sell the Norwegian State's oil and gas together with our own as a single economic unit is likely to be prejudiced. Loss of the mandate to sell the SDFI's oil and gas could have an adverse effect on our position in our markets. For further information about the Norwegian State's coordinated ownership strategy, see section 3.13 Operational review-Related party transactions and Section 6.4 Shareholder information-Major shareholders.

5.2 Risk management

Our overall risk management approach includes identifying, evaluating, and managing risk in all our activities. We manage risk to secure safe operations and to reach our corporate goals in compliance with our requirements.

We have an enterprise-wide risk management approach which means we:

- have a risk and reward focus at all levels in the organisation
- evaluate significant risk exposure related to major commitments
- manage and coordinate risk at corporate level

We divide risk management into three categories:

- Strategic risks which are long-term fundamental risks monitored by our Corporate Risk Committee. Our Corporate Risk Committee, which is headed by our Chief Financial Officer and which includes, among others, representatives from our principal business segments, is responsible for reviewing, defining and developing our strategic market risk policies. The Committee meets monthly to determine our risk management strategies, including hedging and trading strategies and valuation methodologies.
- Tactical risks which are short-term trading risks based on underlying exposures managed by our principle business segment line managers, and
- Operational risks such as those described under risk factors and which cover all major operational goals and underlying risk drivers are managed by our principle business segment line managers. In addition, insurable risks are managed by our captive insurance company operating in the Norwegian and international insurance markets.

To address our strategic and tactical risks, we have developed policies aimed at managing the volatility inherent in certain of these natural business exposures, and in accordance with these policies we enter into various financial and commodity-based transactions (derivatives). While the policies and mandates are set at the group level, the business areas responsible for marketing and trading commodiites are also responsible for managing the commodity-based price risks. The interest-, liqudity-, liability-, and credit risks are managed centrally by the finance department.

The following section describes in some detail the market risks that we are exposed to and how we manage these risks.

5.2.1 Financial risk and financial risk management

The results of our 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, in which the trading price of crude oil is generally stated and to which natural gas prices are frequently related, and NOK, in which our accounts are reported and a substantial portion of our costs are incurred; our oil and natural gas production volumes, which in turn depend on entitlement volumes under PSAs and available petroleum reserves, and our own, as well as our partners' expertise and co-operation in recovering oil and natural gas from those reserves; and changes in our portfolio of assets due to acquisitions and disposals.

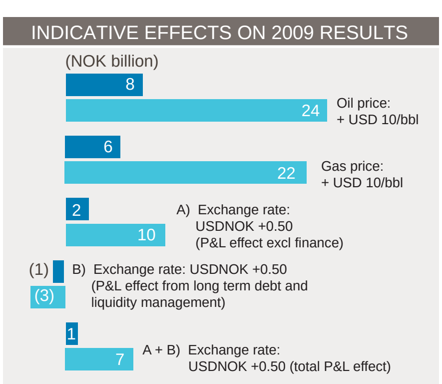
Our results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which we operate, or possible or continued actions by members of the Organisation of Petroleum Exporting Countries (OPEC) that affect price levels and volumes; refining margins; increasing cost of oilfield services, supplies and equipment; increasing competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, which may cause substantial changes to the existing market structures and to the overall level and volatility of prices.

The following table shows the yearly averages for quoted Brent Blend crude oil prices, natural gas contract prices, fluid catalytic cracking (FCC) margins and the USDNOK exchange rates for 2008, 2007 and 2006.

Yearly average	2008	2007	2006
Crude oil (USD/bbl brent blend)	**91**	70.5	63.2
Natural gas (NOK per scm) [1]	**2.4**	1.66	1.94
FCC margins (USD/bbl) [2]	**8.2**	7.5	7.1
USDNOK average daily exchange rate	**5.63**	5.86	6.42

[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 our financial results in 2009.

The estimated sensitivity of each of the factors on our financial results 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 flows.

Fluctuating foreign exchange rates can have a significant impact on our operating results. Our revenues and cash flows are mainly denominated in or driven by US dollars, while our operating expenses and income taxes payable largely accrue in NOK. We 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. We 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 the USD in relation to NOK can be expected to increase our reported earnings. Please see section 5.2.2 Risk review-Risk management-Quantative and qualitative disclosures about market risk. Please see section 4.4 Financial performance - Accounting standards for a description of the expected effects on reported financial results of the change in functional currency of the parent company.

We sell the Norwegian State's share of oil and natural gas production from the NCS. Amounts payable to the Norwegian State for these purchases are included as Accounts payable - related parties in the consolidated balance sheets. The pricing of the crude oil is based on market reflective prices. NGL prices are based on either attained prices, market value or market reflective prices.

StatoilHydro sells, in its own name, but for the Norwegian State's account and risk, the State's natural gas production. This sale, as well as related expenses refunded by the State, is shown net in our financial statements. Expenses refunded by the State include expenses incurred in connection with activities and investments that are necessary in order to secure market access and optimise the profit from the sale of the Norwegian State's natural gas. For sales of the Norwegian State's natural gas, both for our own use and to third parties, the payment to the Norwegian State is based on prices attained, a net back formula or market value. We purchase a small proportion of the Norwegian State's gas. For further details see section 3.13 Operational review-Related party transactions.

High oil prices have contributed to higher earnings and profitability from international projects with PSAs than previously anticipated. Under a PSA, the partners are generally entitled to production volumes that cover the development costs and an agreed share of the remaining volumes. When oil prices are high, this means that these projects will move from a phase where earnings cover development costs to a phase where profits are generated at an earlier point in time. In PSA contracts, the higher the oil price, the sooner the field is profitable and the smaller is the share of the production that goes to the partners. The actual effect varies between different agreements and countries. See section 4.1.9 Financial performance-Strong operational performance-Reported volumes above for a description of the impact of the PSA effects.

Historically, our revenues have largely been generated from the production of oil and natural gas on the NCS. Norway imposes a 78% marginal tax rate on income from offshore oil and natural gas activities. See section 3.10.5 Operational review-Regulation-Taxation of StatoilHydro. Our earnings volatility is moderated as a result of the significant proportion of our Norwegian offshore income that is subject to a 78% tax rate in profitable periods, and the significant tax assets generated by our Norwegian offshore operations in any loss-making periods. Most of the taxes we pay are paid to the Norwegian State. Since 1 January 2004, dividends received have not been subject to tax in Norway. Exemptions are granted for dividends from low-tax countries or portfolio investments outside the EEA.

Government fiscal policy is an issue in several of the countries in which we operate, such as, but not limited to, Venezuela, the United States, Algeria and Angola. For instance, government fiscal policy could require royalties in cash or in kind, increased tax rates, increased government participation, and changes in terms and conditions as defined in various production or income sharing contracts. Our financial statements are based on currently enacted regulations and on any current claims from tax authorities regarding past events. Developments in government fiscal policy may have a negative effect on future net income.

Financial risk management

Our business activities naturally expose us to risk. The group's approach to risk management includes identifying, evaluating, and managing risk in all our 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 we utilise 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 (i.e. utilize the natural hedges embedded in our portfolio). This approach also reduces the number of unnecessary transactions (i.e. reducing transaction costs and avoiding sub-optimisation).

In order to achieve the above effects, the group has centralized trading mandates such that all major/ strategic transactions are co-ordinated through our Corporate Risk Committee. This implies that local trading mandates are relatively small.

Our Corporate Risk Committee which is headed by our Chief Financial Officer and which includes, among others, representatives from our principal business segments is responsible for defining, developing, and reviewing our risk policies. The Chief Financial Officer in co-operation with the Corporate Risk Committee is also responsible for overseeing and developing StatoilHydro's Enterprise-Wide Risk Management and proposing appropriate risk adjusting measures at the corporate level. To help facilitate its role, the Committee meets at least six times per annum and regularly receives risk information relevant for the group from our Corporate Risk Department.

The financial risk management covers market risks including commodity price risk, interest rate risk, currency risk and equity price risk; liquidity risk; and credit risk.

Market risk management

Strategic market risk

We define strategic market risks as long-term risks fundamental to the operation of our business. These risks are monitored and reviewed with the objective of avoiding sub-optimisation, reducing the likelihood of experiencing financial distress and supporting the Group's ability to finance future growth even under adverse market conditions. Based on these objectives, policies and procedures have been implemented to reduce our overall exposure to strategic risks.

Tactical market risk
All tactical risk management activities occur within and are continuously monitored against established mandates.

Commodity price risk
Commodity price risk constitutes our most important tactical market risk. To manage the commodities price risk, we enter into commodity-based derivative contracts, which consist of futures, options, over-the-counter (OTC) forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity.

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 three years or less. The commodity price risk is managed by the marketing and trading organisations in the Natural gas and Manufacturing and Marketing segments, respectively. The risks are managed in the trading currencies of the commodities in question, and not necessarily in the functional or reporting currency of the company.

Currency risk
We consider StatoilHydro to be a USD company for currency management purposes. Fluctuations in exchange rates can have significant effects on our results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates. We use only well-understood, conventional derivative instruments which include futures and options traded on regulated exchanges, OTC swaps, options and forward contracts.

Our cash inflows are largely denominated in or driven by USD while our cash outflows mainly derive from tax and dividend payments in NOK, as well as certain investments, payment of salaries and various other costs payable in NOK. Accordingly, our exposure to foreign currency rates exists primarily with USD versus NOK. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

We further seek to manage short-term currency mismatches by using derivative instruments both for currency and liquidity management purposes. Typically, we purchase NOK during the course of a calendar year in order to cover projected NOK payments of Norwegian income taxes and dividends in the first half of a subsequent year. This means, from time to time, we purchase substantial NOK amounts on a forward basis using derivative instruments.

Interest rate risk
The existence of assets earning and liabilities owing variable rates of interest expose us to cash flow risk caused by interest rate fluctuations. We enter into various types of interest rate contracts in managing our interest rate risk. We enter 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. Under interest rate swaps, we agree with other parties to exchange, at specified intervals, the difference between interest amounts calculated by reference to an agreed notional principal amount and agreed fixed or floating interest rates.

We principally manage our interest rates on the basis that the non-current debt portfolio has floating rate interest payments. The modified duration (the percentage change in value for one percentage point change in yield) expresses the way we monitor the interest rate risk. Generally, our modified duration is to be be between 0 and 1.0%. Other strategies can be approved from time to time if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

Liquidity risk management
Liquidity risk is the risk that we will not be able to meet our obligations when due. The purpose of liquidity and short term liability management is to make certain that the group at all times has sufficient funds available to cover financial obligations.

StatoilHydro's business activities normally generate, on a monthly basis, a positive cashflow from operations. However, in months when taxes are paid (February, April, June, August, October and December) or annual dividend is paid (typically in May/June) cashflows are typically limited. Our operating cashflows are negatively impacted by declines in oil and gas prices, however, during 2008 our overall liquidity position remained strong and our policies for managing liquidity remained unchanged.

The amount of liquid assets will, as a rule, follow a cyclical pattern and increase from month to month, with an exception for months with tax or dividends payments when the amount is sharply reduced. In the period following tax and dividend payments the amount of liquid assets will often be significantly reduced. A need for short-term funding will then be triggered for a period until the debt is repaid and subsequently followed by a new accumulation of liquid assets.

Short-term funding can be carried out bilaterally through direct borrowing from banks, insurance companies, etc. An alternative is to issue short term debt securities under one of the existing funding programmes or under documentation established ad hoc. These funding programmes are as follows:

- A USD 4 billion US commercial paper programme. This is the most flexible programme used for working capital, including timing issues on corporate tax and dividend payments, as well as for periodic acquisition financing.
- A USD 2 billion committed multi-currency revolving credit facility from international banks, including a USD 500 million swing-line facility. The facility was entered into in 2004, and is available for draw-downs until December 2011. This facility is primarily intended as a "back-up" facility for the US commercial paper programme, and should be regarded as support for the credit rating of this programme.
- Uncommitted credit lines. Short-term funding source occasionally required beyond the other short-term programmes and accumulated cash.

In order to have access to sufficient liquidity at all times, StatoilHydro defines and continously maintains a minimum liquidity reserve which comprises unused committed external credit facilities, cash and cash equivalents, and current financial investments excluding the current portion of the investment portfolio held by the group's captive insurance subsidiary.

	at 31 December	
Liquid assets as (in NOK billion)	**2008**	**2007**
Cash & cash equivalents	**18.6**	18.3
Financial investments	**9.7**	3.3
Total liquid assets	**28.4**	21.6

Funding and liability

As a basic principle we separate investment decisions from financing decisions. Funding needs arise as a result of the Group's general business activity. The main rule is to establish financing at corporate level. Project financing may be applied in cases involving joint ventures with other companies.

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

We have credit ratings from Moody's and Standard & Poor's and the stated objective is to have a rating at least within the single A category. This rating ensures necessary predictability when it comes to funding access at favourable terms and conditions. Our current long-term 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 intend to keep financial ratios relating to our debt at levels consistent with our objective of maintaining our long-term credit rating at least within the single A category. To sustain financial flexibility going forward we seek to maintain a credit rating at least within the single A category. In this context we carry out different risk assessments, some of them in line with financial matrixes used by S&P and Moody's, such as free funds from operations over net debt and net debt to capital employed.

In order to control our refinancing risk, the maturity and redemption profile of non-current debt issued is managed within certain limitations. The limits are expressed as maximum annual mandatory redemptions as a share of StatoilHydro's capital employed.

Liquidity forecasts serve as tools for financial planning. In order to maintain necessary financial flexibility, we have requirements for maximum (forecasted) current debt and minimum (forecasted) liquidity reserve. Issuance of long term debt is used as a tool for reducing current debt and/or increasing the liquidity reserve. New non-current funding will be initiated if liquidity forecasts reveal non-compliance with given limits, unless further detailed considerations indicate that the non-compliance is likely to be very temporary. In this case, the situation will be further monitored before additional non-current debt is drawn.

For further information on our debenture bonds, bank loans, and other debt portfolio profile, see note 24-Current financial liabilities to our Consolidated Financial Statements in this report.

StatoilHydro's dividend policy includes providing a return to our shareholders through cash dividends and share repurchases. The level of cash dividends and share repurchases in any one year can fluctuate depending on our assessment of future cashflows, capital expenditure plans, financing requirements, and appropriate financial flexibility. See note 19-Shareholders equity for additional information on our dividend policy.

Credit risk management

Credit risk is the risk that our customers or counterparties to financial instruments will cause us financial loss by failing to honour their obligations. Credit risk arises from credit exposures with customer accounts receivables as well as from derivate 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 2008 and NOK 7.5 billion in 2007), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents. The group manages this exposure through its credit risk management policies and procedures.

The current financial crisis has brought additional focus on the need for all entities to have robust credit policies with close monitoring of associated risks. Over the years, we have established a clear credit policy which has proven especially valuable during this period of widespread financial pressure. The tools we use to manage and monitor credit risk have been tested by the continuing crisis and no significant credit losses have realised for the group during 2008.

Key elements of our credit risk management approach include

- A conservative global credit risk policy
- Credit mandates
- Internal credit rating process
- Credit risk mitigation tools
- Continuously monitoring and managing credit exposures

Prior to entering into transactions with new counterparties, our 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 minimum annually with high risk counterparties reviewed more frequently. The internal credit ratings reflect our assessment of the counterparties' credit risk and are similar to rating categories used by well known credit rating agencies, Standard & Poor's and Moody's. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics, as outlined in our credit policy. The mandate for setting credit limits is regularly reviewed with regard to changes in market conditions.

There are several instruments available to us to reduce or control credit risk both on an individual counterparty and portfolio level. The main tools used by StatoilHydro are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only highly rated international banks are accepted.

We manage credit risk both on a portfolio and counterparty level. We have pre-defined limits regarding the minimum average credit rating allowed at any given time on the group portfolio level as well as maximum credit exposures for individual counterparties. We monitor the portfolio on a regular basis and individual exposures versus limits on a daily basis. The total credit exposure portfolio of StatoilHydro is well diversified with respect to number and quality of counterparties, industries and geographically. The majority of our credit exposure is typically with investment grade counterparties.

The following table contains the average credit exposure by counterparty by internal credit rating and includes the rating categories share of the group's total exposure:

The following table contains the fair market value of open non-exchange traded derivative assets split by our assessment of the counterparty's credit risk:

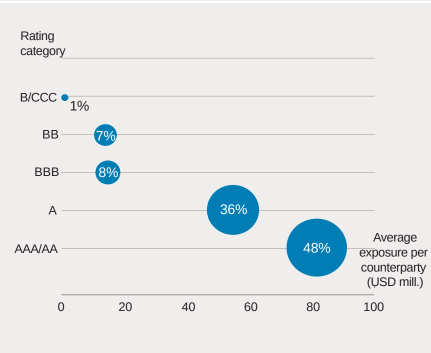
In accordance with our internal credit rating policy, we reassess counterparty credit risk at least annually and assess counterparties that we identify as high risk more frequently. The internal credit ratings reflect our assessment of the counterparties' credit risk and are similar to rating categories used by well known credit rating agencies, such as Standard & Poor's and Moody's. The mandate for setting credit limit is regularly reviewed with regard to changes in market conditions.

	At 31 December	
(in NOK million)	**2008**	**2007**
Counter-party rated:		
Investment grade, rated A or above	21,727	19,647
Other investment grade	7,094	928
Non-investment grade or not rated	761	689

As of 31 December 2008, NOK 10.1 billion is held as collateral in the Group to offset a portion of this credit exposure.

Consistent with our policies, commodity derivative counter-parties have been assigned credit ratings corresponding to those of their respective parent companies. If the parent company is highly rated, it may not be necessary to obtain a parent company guarantee from such a counterparty.

CREDIT EXPOSURE ON RATING CATEGORY



The graph illustrates the magnitude as per 31 December 2008 of our credit risk exposure sorted by our assessment of the counterparties' credit risk. As can be seen from the illustration, most of our credit risk exposure is with counterparties assessed by us to have investment grade credit rating. Our assessment of each counterparty's credit risk is often consistent with the credit ratings published by credit rating agencies but may vary on a case by case basis due to differences in the timing and or the judgments inherent in the specific credit risk assessment. Our assessment of each counterparty's credit risk may also change over time due to changes in company specific or general conditions.

The illustration above reflects the credit risk exposure that StatoilHydro has to its counterparties as 31 December 2008. Credit ratings of such counterparties may be subject to revision or withdrawal at any time in accordance with our internal credit rating policy, and any such change to a counterparty's credit rating may affect StatoilHydro's credit risk exposure.

5.2.2 Quantitative and qualitative disclosures about market risk

StatoilHydro uses financial instruments to manage commodity price risks, interest rate risks, currency risks and liquidty and funding risks, and significant amounts of assets and liabilities are accounted for as financial instruments.

See note 29 Financial instruments by category to the Consolidated Financial Statements for details on the nature and extent of such positions and note 30 Financial instruments and hedging for qualitative and quantitative disclosures of the risks associated with these instruments.

5.3 Legal proceedings

We are involved in a number of judicial, regulatory and arbitration proceedings concerning matters arising in connection with the conducting of our business.

Except as set forth below, we are currently not aware of any legal proceedings or claims that we believe could, individually or in the aggregate, have significant effects on our financial position or profitability or on the results of our operations or liquidity.

The AFT case

StatoilHydro 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 StatoilHydro 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 on 29 April 2008 issued a writ involving a multi-component compensation claim, the aggregate principal exposure of which for StatoilHydro approximates between NOK 4 and 7 billion after tax. During the fourth quarter of 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, has issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. StatoilHydro rejects both claims.

The Libya case

StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to StatoilHydro as of 1 October 2007 as part of the merger with Hydro's petroleum business, and which could be in conflict with applicable Norwegian and US anti-corruption legislation. Following a preliminary assessment by StatoilHydro, 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 StatoilHydro 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 Securites and Exchange Commission and Libyan authorities. The report does not draw any legal conclusions and in accordance with the mandate for the review only entails the facts relevant to applicable Norwegian and US anti-corruption legislation to which StatoilHydro ASA may be subject as a result of the merger.

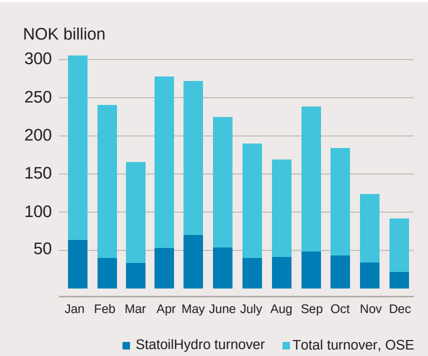
6 Shareholder information

StatoilHydro is the largest company listed on the Oslo stock exchange (Oslo Børs), where it trades under the ticker code STL.

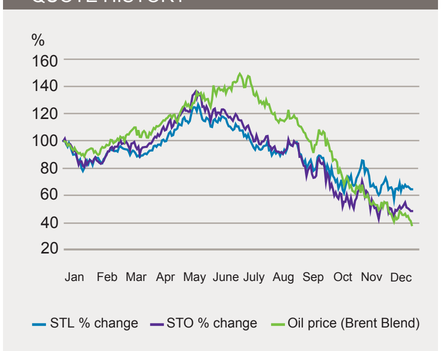
StatoilHydro share	2008	2007	2006	2005	2004
Share price STL high (NOK)	**214.10**	191.50	210.50	166.50	103.50
Share price STL low (NOK)	**96.40**	151.50	147.25	91.25	74.00
Share price STL year-end (NOK)	**113.90**	169.00	165.25	155.00	95.00
Market value year-end (NOK billion)	**363**	539	358	336	206
Daily turnover (million shares)	**13.5**	16.5	12.6	10.1	6.7
Ordinary and diluted earnings per share (EPS) (NOK) [1]	**13.58**	13.80	15.82	14.19	11.50
P/E [1] [2]	**8.39**	12.25	10.45	10.92	8.26
Dividend paid per share (NOK) [3]	**7.25**	8.50	9.12	8.20	5.30
Pay-out ratio [4]	**53%**	61%	57%	58%	46%
Dividend yield [5]	**6.4%**	5.0%	5.5%	5.3%	5.6%
Net debt to capital employed [1] [6]	**17.5%**	12.4%	20.5%	15.1%	18.9%
Ordinary shares outstanding, weighted average	**3,185,953,538**	3,195,866,843	3,230,849,707	2,165,740,054	2,166,142,636
Ordinary shares outstanding, year-end	**3,188,647,103**	3,188,647,103	3,208,800,400	2,189,585,600	2,189,585,600

1) Figures for 2004 and 2005 are USGAAP, only former Statoil figures.
2) Share price at year-end divided by EPS.
3) Proposed dividend for 2008. Including ordinary and special dividend.
4) Dividend paid per share divided by EPS. Total capital distribution in 2006 is 67%, including share buy-back of NOK 1.55 per share in 2006.
5) Dividend paid per share divided by year-end share price.
6) The relationship between net interest-bearing debt and capital employed.

TURNOVER



QUOTE HISTORY



Turnover of shares is a measure of traded volumes. On average, 13.5 million StatoilHydro shares were traded on the Oslo Børs every day in 2008, a decrease of 18% on the previous year. StatoilHydro shares accounted for 21.1% of the total market value traded throughout the year (see illustration).

As of 31 December 2008, StatoilHydro represented 36% of the total value of all companies registered on the Oslo Børs, with a market value of NOK 363 billion.

The group's share price decreased from NOK 169.00 at the end of 2007 to NOK 113.9 at the end of 2008. The Board of Directors proposes an ordinary dividend of NOK 4.40 per share for 2008, as well as NOK 2.85 per share as special dividend for approval by the Annual General Meeting on 19 May 2009. The total dividend of NOK 7.25 per share proposed to be distributed to our shareholders is equivalent to a direct yield of approximately 6.4%, and we will distribute 53% of net income from 2008. Net income per share amounted to NOK 13.58 in 2008, a decrease of 1.6% compared to 2007.

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

On average, 13.5 million StatoilHydro shares were traded on the Oslo Børs every day in 2008, a decrease of 18% on the previous year. StatoilHydro shares accounted for 21.1% of the total market value traded throughout the year (see illustration).

As of 31 December 2008, StatoilHydro had approximately 103,400 shareholders registered in the Norwegian Central Securities Depository (VPS), an increase corresponding to 6% on the year before. The number of American Depositary Receipts traded on the New York Stock Exchange decreased by 4% during the course of the year.

6.1 Dividend policy

Our dividend policy reflects our ambition to return an amount in the range of 45 to 50% of consolidated net income pursuant to IFRS to our shareholders, through cash dividends and share repurchases.

It is StatoilHydro's ambition to grow the ordinary cash dividend measured in NOK per share. Furthermore, it is StatoilHydro's intention to return to it shareholders, through cash dividends and share repurchases, an amount in the range of 45 to 50 percent of consolidated net income as determined in accordance with IFRS. In any one year, however, the aggregate of cash dividends and share repurchases may be higher or lower than 45 to 50 percent of net income, depending on the company's evaluation of expected cash flow, capital expenditure plans, financing requirements and appropriate financial flexibility.

For more information on the purchase of StatoilHydro shares, see the report section 6.2 Shareholder information-Equity securities purchased by issuer.

6.1.1 Dividends

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

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

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

Although we currently intend to pay annual dividends on our ordinary shares, we cannot assure that dividends will be paid or as to the amount of any dividends. Future dividends will depend on a number of factors prevailing at the time our board of directors considers any dividend payment.

The following table shows the cash dividend amounts paid to all shareholders since 2006 on a per share basis and in the aggregate, as well as cash dividends proposed by our board of directors to be paid in 2009 on our ordinary shares for the fiscal year 2008.

In 2006, 2007 and 2008 the total dividend per share represented an ordinary dividend and a special dividend. The total cash dividend per share proposed by the board of directors for 2009 also includes an ordinary dividend and a special dividend. The special dividends paid in these years are the result of increased annual net income due to higher realized oil and gas prices. There is no guarantee that special dividends will be paid in the future, even if higher oil and gas prices are sustained over time.

	Per ordinary share[1)]			
Year	Ordinary dividend NOK	Special dividend NOK	Total dividend NOK	Total NOK billion
2004	3.20	2.10	5.30	11.5
2005	3.60	4.60	8.20	17.8
2006	4.00	5.12	9.12	19.7
2007	4.20	4.30	8.50	27.1
2008	4.40	2.85	7.25	23.1

1) For fiscal years 2008, 2007, 2006, 2005, and 2004 the total dividend per share consisted of an ordinary dividend and a special dividend. The 2008 dividend is expected to be paid in the end of May 2009.

Since we will only pay dividends in Norwegian kroner, exchange rate fluctuations will affect the US dollar amounts received by holders of ADSs after the ADR depositary converts cash dividends into US dollars.

Share repurchases

For the period 2008-2009 the board did not request the Annual General Meeting in StatoilHydro for an authorisation to repurchase StatoilHydro shares in the market for subsequent cancellation, and StatoilHydro therefore did not buy any shares for cancellation in 2008. We did not undertake any share repurchases in 2008 and 2007, and no shares were acquired in the market, for subsequent cancellation. In 2006, 20,158,848 shares were repurchased totalling NOK 3.3 billion.

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

6.2 Equity securities purchased by issuer

6.2.1 StatoilHydro share savings plan

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

Through regular salary deductions, employees can invest for an amount up to 5% of their basic salary in StatoilHydro shares. In addition, the company contributes with 20% of the amount, up to a maximum of NOK 1500. This company contribution is a tax free employee benefit under the current Norwegian tax legislation. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. The share award is a taxable employee benefit, with a value equal to the value of the shares and taxed at the time of the award, under the current Norwegian tax legislation. Shares transferred to employees are acquired by the company in the market.

The board decides the manner in which the acquisition of StatoilHydro shares in the market takes place. Shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the StatoilHydro group as part of the group's share investment plan as approved by the board. The minimum and maximum amount that may be paid per share will be NOK 50 and NOK 500, respectively. Within these limits, the board of directors may freely decide when shares are acquired, although the purchases follow a fixed plan for one year at a time. The authorisation was last renewed on 20 May 2008 and is valid until the next annual general meeting.

The nominal value of each share is NOK 2.50. At a maximum overall nominal value of NOK 15 million, the authorisation for the repurchase of shares in connection with the group's share savings plan covers the repurchase of no more than six million shares.

Share savings plan.

Period in which shares where repurchased	Number of shares repurchased	Average price per share in NOK	Total number of shares purchased as part of program [1]	Maximum number of shares that may yet be purchased under the program authorisation [1]
January 2008	364,000	146.15	2,088,300	3,911,700
February 2008	347,000	153.30	2,435,300	3,564,700
March 2008	341,000	156.23	2,776,300	3,223,700
April 2008	315,012	168.10	3,091,312	2,908,688
May 2008	265,000	198.49	3,356,312	2,643,688
June 2008	269,850	195.67	269,850	5,730,150
July 2008	313,000	169.66	582,850	5,417,150
August 2008	340,000	154.75	922,850	5,077,150
September 2008	381,574	138.95	1,304,424	4,695,576
October 2008	453,000	118.89	1,757,424	4,242,576
November 2008	467,100	117.78	2,224,524	3,775,476
December 2008	598,000	107.84	2,822,524	3,177,476
January 2009	521,800	116.64	3,344,324	2,655,676
February 2009	494,500	123.08	3,838,824	2,161,176
Total	5,470,836 [2]	141.08 [3]	3,838,824	2,161,176

[1] The authorisation to repurchase a maximum of six million shares with a maximum overall nominal value of NOK 15 million for repurchase of shares in connection with the group's share investment plan was given by the annual general meeting on 15 May 2007. The authorisation was renewed by the annual general meeting on 20 May 2008 maintaining a maximum of six million shares with a maximum overall nominal value of 15 million for repurcase of shares, and valid until June 2009.

[2] All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

[3] Weighted average price per share.

6.2.2 Purchase of shares for cancellation

The Board did not request the General Meeting in StatoilHydro for an authorisation to repurchase StatoilHydro shares in the market for subsequent cancellation in the period 2008-2009.

This was due to the Norwegian government's stated intention to increase its ownership interest in StatoilHydro from 62.5% to 67%. As of 5 March 2009, the Norwegian State owns a 66.89% interest in StatoilHydro and a 3.94% through Folketrygdfondet, total 70.83% interest in StatoilHydro. Now that the Government has reached its stated intended ownership share, the Board may ask the General Meeting for a new share repurchase authorisation.

In 2007, the annual general meeting of Statoil authorised the board of directors to acquire Statoil shares in the market for subsequent cancellation. This authorisation was valid until 20 May 2008. StatoilHydro did not make use of this authorisation in 2007 or 2008.

In accordance with the resolution of the extraordinary general meeting on 5 July 2007 and with the authorisation to repurchase shares granted by the annual general meeting on 10 May 2006, Statoil carried out a capital reduction in September 2007 through the redemption and cancellation of a total of 20,158,848 shares with a nominal value of NOK 2.50 per share, of which 14,291,848 shares were redeemed from the Norwegian State, represented by the Ministry of Petroleum and Energy, and canceled.

6.3 Information and communications

Keeping the market updated about StatoilHydro's financial performance and future prospects is important to us.

Information provided to the stock market must be transparent and ensure equal treatment, and it must aim to provide shareholders with correct, clear, relevant and timely information that forms a basis for assessing the value of the company.

The StatoilHydro share is listed on the stock exchanges in Oslo and New York, and the company distributes its share price sensitive information through the international wire services, the Oslo Stock Exchange in Norway, the Securities and Exchange Commission in the US, and the company website.

Our registrar manages our shares listed on the Oslo stock exchange on our behalf and provides the connection to the Norwegian Central Securities Depository (VPS). Major services provided by the registrar are investor services for private shareholders, the disbursement of dividend and assistance at our general meetings. The DnB NOR bank is currently account registrar for StatoilHydro.

6.3.1 Investor contact

Our investor relations staff function (IR) coordinates the dialogue with our shareholders.

We place great emphasis on ensuring that relevant and timely information is distributed to the capital markets. Given the size and diversity of our shareholder base, the opportunities for direct shareholder interaction are limited to a certain extent. Our investor relations web pages are therefore specially designed for investors and analysts who wish to follow the company's progress - http://www.statoilhydro.com/ir

Our quarterly presentations and other relevant presentations by management are broadcasted directly on the internet, and the pertaining reports are made available together with other relevant information on the company's website.

StatoilHydro meets the requirements for the information symbol and English symbol issued by Oslo Børs.

Ticker Codes

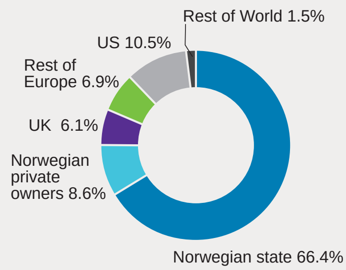
Oslo Børs STL
New York Stock Exchange STO
Reuters STL.OL
Bloomberg STL NO

6.4 Major shareholders

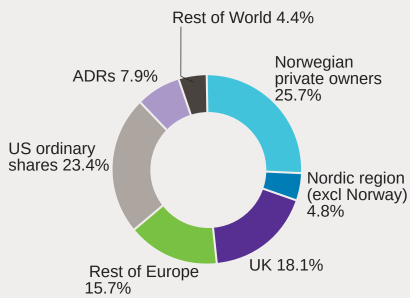
The Norwegian State is the largest shareholder in StatoilHydro. Its ownership interest is managed by the Ministry of Petroleum and Energy.

Statoil was partially privatised and listed on the stock exchange on 18 June 2001, when it became a public limited company. After the initial offering, the government retained 81.7% of the Statoil shares. From 2005 and prior to the merger with Hydro's oil and energy activities in 2007, the Norwegian state owned 70.9% of the shares in Statoil.

DISTRIBUTION OF SHAREHOLDERS



FREE FLOAT BREAKDOWN



Pursuant to the agreed exchange ratio as part of the merger with Hydro's oil and gas activities, the State's ownership interest in StatoilHydro was 62.5%, or 1,992,959,739 shares on 1 October 2007. In accordance with the Storting's decision of 2001 concerning a minimum state shareholding of two-thirds in Statoil, the Government expressed its intention to increase the state's shareholding in StatoilHydro over time to 67%. During 2008 the Government has built up the State's ownership interest in StatoilHydro by buying shares in the market. On 31 December 2008 the State's ownership interest in StatoilHydro was 66.42%, or 2,117,961,391 shares. On 5 March 2009 the Government announced that the State's ownership interest has reached 67%, and the Government's purchase of StatoilHydro shares was completed by acquiring 143.3 million shares for a combined NOK 19.3 billion since 2 June 2008. As of 12 March 2009 the Norwegian State had a 67% ownership interest in StatoilHydro and 3.94% interest through Folketrygdfondet, totalling 70.94%.

As of 12 March 2008, the National Insurance Fund, (Folketrygdfondet) owned 125,688,100 shares, or 3.94% of the total number of ordinary shares. The Norwegian State is the only person or entity known to us to own beneficially, directly or indirectly more than 5% of our outstanding shares. We have not been notified of any other beneficial owner of 5% or more of our ordinary shares as of 6 March 2009.

In June 2001, in connection with the initial public offering of our ordinary shares, we established a sponsored American Depositary Receipt facility with The Bank of New York Mellon (formerly known as The Bank of New York) as depositary, pursuant to which American Depositary Receipts (ADRs) representing American Depositary Shares (ADSs) are issued. We have been informed by The Bank of New York Mellon that in the United States, as of 6 March 2009, there were 75,227,150 ADRs outstanding (representing approximately 2.36% of the ordinary shares outstanding). As of 6 March 2009 there were 724 registered holders of ADRs resident in the United States and 293,178,809 ordinary shares were held by 546 registered holders resident in the United States representing approximately 9% in total.

StatoilHydro has one class of shares, and each share confers one vote at the general meeting. The Norwegian State does not have any different voting rights from the rights of other ordinary shareholders. Pursuant to the Norwegian Public Limited Liability Companies Act, a majority of more than two-thirds of the votes cast as well as of the votes represented at a general meeting is required to amend our articles of association. As long as the Norwegian state owns more than one-third of our shares, it will be able to prevent any amendments to our articles of association.

Since the Norwegian State, acting through the Minister of Petroleum and Energy, has increased its holding in excess of two-thirds of the shares in the company, it has the sole power to amend our articles of association. In addition, as a majority shareholder, the Norwegian State has the power to control any decision at general meetings of our shareholders that requires a majority vote, including the election of the majority of the corporate assembly, which has the power to elect our Board of Directors and approve the dividend proposal by the Board of Directors.

The Norwegian State endorses the principles set out in "The Norwegian Code of Practice for Corporate Governance", and it has stated that it expects companies in which the State has ownership interests to adhere to the code. The principle of ensuring equal treatment of different groups of shareholders is a key element in the State's own guidelines. In companies in which the State is a shareholder together with others, the State wishes to exercise the same rights and obligations as any other shareholder and not act in a manner that has a detrimental effect on the rights or financial interests of other shareholders. In addition to the principle of equal treatment of shareholders, emphasis is also placed on transparency in relation to the State's ownership and on the general meeting being the correct arena for owner decisions and formal resolutions.

Shareholders at 6 March 2009	Type	Number of shares	Ownership in %
The Norwegian State (Ministry of Petroleum and Energy)		2,132,829,691	66.89
Folketrygdfondet (Norwegian national insurance fund)		125,738,100	3.94
Bank of New York ADR Department	Nominee	70,014,750	2.20
State Street Bank	Nominee	47,552,749	1.49
Clearstream Banking	Nominee	43,111,702	1.35
State Street Bank	Nominee	42,652,342	1.34
JPMorgan Chase Bank	Nominee	36,231,346	1.14
Bank of New York Mellon	Nominee	27,041,941	0.85
The Northern Trust	Nominee	17,020,750	0.53
JPMorgan Chase Bank	Nominee	16,881,926	0.53
Bank of New York Mellon	Nominee	16,025,000	0.50
The Northern Trust	Nominee	15,532,513	0.49
Investors Bank	Nominee	14,343,718	0.45
The Northern Trust	Nominee	13,205,834	0.41
DnB NOR Bank ASA		10,650,794	0.33
The Northern Trust	Nominee	9,498,114	0.30
Svenska Handelsbanken	Nominee	8,685,780	0.27
State Street Bank	Nominee	8,001,335	0.25
DNB NOR Norge		7,884,240	0.25
RBC Dexia Investors	Nominee	7,746,317	0.24

Source: Norwegian Central Securities Depository (VPS)

6.5 Market and market prices

The principal trading market for our ordinary shares is the Oslo stock exchange on which the shares have been listed since our initial public offering on 18 June 2001.

The ordinary shares are also listed on the New York Stock Exchange, trading in the form of American Depositary Shares (ADSs), evidenced by American Depositary Receipts (ADRs). Each ADS represents one ordinary share. StatoilHydro has a sponsored ADR facility with the Bank of New York as Depositary.

For the periods indicated, the following tables show the reported high and low quotations at market closing for the ordinary shares on Oslo Børs, as derived from its Daily Official List, and the highest and lowest sales prices of the ADSs as reported on the New York Stock Exchange composite tape.

Share price	NOK per ordinary share High	Low	USD per ADS High	Low
Year ended 31 December				
2004	103.50	74.00	15.93	10.85
2005	166.50	91.25	25.80	14.69
2006	210.50	14.25	34.52	22.39
2007	191.50	151.50	35.19	23.90
2008	214.10	96.40	42.47	13.37
Quarter ended				
31 March 2007	167.50	151.50	28.00	23.90
30 June 2007	183.50	162.25	31.03	26.01
30 September 2007	191.50	153.00	34.93	25.53
31 December 2007	187.00	159.90	35.19	28.77
31 March 2008	169.90	135.30	31.76	25.30
30 June 2008	214.10	155.00	42.47	30.35
30 September 2008	187.10	130.60	36.95	21.85
31 December 2008	144.80	96.40	23.06	13.37
March up until 6 March 2009	131.00	108.90	18.64	15.11
Month of				
September 2008	160.30	130.60	27.67	21.85
October 2008	135.00	104.50	23.06	15.72
November 2008	144.80	102.00	22.00	13.37
December 2008	116.60	96.40	17.13	13.93
January 2009	131.00	113.00	18.64	15.72
February 2009	123.70	112.90	18.31	16.01
March up until 6 March 2009	117.30	108.90	16.51	15.11

6.6 Taxation

This section describes the material Norwegian tax consequences that apply to shareholders resident in Norway as well as to non-resident shareholders in connection with the acquisition, ownership and disposal of shares and ADSs.

Norwegian tax matters
This section does not provide a complete description of all tax regulations which might be relevant (i.e. for investors to whom special regulations may be applicable). This section is based on current law and practice. Shareholders should consult their professional tax adviser for advice concerning individual tax consequences.

Taxation of dividends
Under the participation exemption model, corporate shareholders resident in Norway for tax purposes are exempt from tax on dividends distributed by Norwegian companies. However, effective from 7 October 2008, 3% of net income that is tax free under the participation exemption will be included in the Norwegian corporate shareholder's general taxable income. For individual shareholders, double taxation applies: Dividend income exceeding a "deductible allowance", which is an amount equal to the risk-free interest after tax on the base cost of the shareholding, will be taxable at a flat rate, currently 28%. The average interest on Treasury bills of 3 months' maturity will be applied.

Non-resident shareholders are as a general rule subject to withholding tax at a rate of 25% on dividends distributed by Norwegian companies. This withholding tax does not apply to corporate shareholders that document that they are genuinely resident for tax purposes in a country in the European Economic Agreement area (EEA area) and that it is involved in genuine economic business activity in that country, provided that Norway is entitled to receive information from the state of residency according to a tax treaty or other international treaty. If no such treaty exists with the state of residency, the shareholder may instead present a certification issued by the tax authorities of the state of residency verifying the documentation.

The withholding rate of 25% is often reduced in tax treaties between Norway and other countries. Generally, the treaty rate does not exceed 15% and, in cases where a corporate shareholder holds a qualifying percentage of the shares of the distributing company, the withholding tax rate on dividends may be further reduced. The withholding tax rate in the tax treaty between the United States and Norway is currently 15% in all cases. The treaty is currently being renegotiated, but it is uncertain at what point in time a new treaty will be in place. Shareholders that carry on business activities in Norway and whose shares are effectively connected with such activities are not liable to the withholding tax. In such case, the rules described in the above paragraph regarding corporate shareholders resident in Norway apply. We are obliged by law to deduct any applicable withholding tax when paying dividends to non-resident shareholders.

Under the tax treaty between Norway and the United States, the 15% withholding rate will apply to dividends paid on shares held directly by holders who are able to properly demonstrate to the company that they are entitled to the benefits of the tax treaty.

Dividends paid to the depositary for redistribution to shareholders who hold ADSs will in principle be subject to withholding tax of 25%. The beneficial owners will in this case have to apply to the Central Office of Foreign Tax Affairs (COFTA) for a refund of the excess amount of tax withheld.

An application for a refund of withholding tax must contain the following:

1. A specification of the distributing company(ies) involved, the exact amount of shares, the date the dividend payments were made, the total dividend payment, the withholding tax deducted in Norway and the amount that is being reclaimed. The withholding tax must be calculated in Norwegian currency and all sums specified accordingly (in NOK).
2. Documentation that shows that the refund claimant received the dividends and the withholding tax rate that was applied in Norway.
3. A certificate of residence issued by the tax authorities stating that the refund claimant is resident for tax purposes in that state in the income year in question or at the time the dividends were decided. This documentation must be the original document.
4. If the refund application is based on an assertion that the shareholder is covered by the participation exemption method, the application must also contain the information necessary to decide whether the refund claimant is an entity covered by the tax exemption model.
5. The information required to decide whether the refund claimant is the beneficial owner of the dividend payment(s).
6. If the securities are registered with a foreign custodian/bank/clearing house, the claimant must provide information about which foreign custodian/bank/clearing house the securities are registered with in Norway.

The application must be signed by the applicant. If the application is signed by a proxy, a copy of the letter of authorisation must be enclosed.

However, pursuant to agreements with the Financial Supervisory Authority of Norway and the Norwegian Directorate of Taxes, the Bank of New York, acting as depositary, is entitled to receive dividends from us for redistribution to a beneficial owner of shares or ADSs at the applicable treaty withholding rate, if the beneficial holder has provided the Bank of New York with appropriate certification to establish such holder's eligibility for the benefits under the tax treaty with Norway.

Wealth tax. The shares are included in the basis for the computation of wealth tax imposed on individuals who, for tax purposes, are considered to be resident in Norway. Norwegian limited companies and certain similar entities are not subject to wealth tax. Currently, the marginal wealth tax rate is 1.1% of the value assessed. As of 2008, the assessment value of listed shares is 100% of the listed value of such shares on 1 January in the assessment year.

Non-resident shareholders are not subject to wealth tax in Norway for shares in Norwegian limited companies unless the shareholder is an individual and the shareholding is effectively connected with his business activities in Norway.

Inheritance tax and gift tax. When shares or ADSs are transferred, either through inheritance or as a gift, such transfer may give rise to inheritance tax in Norway if the deceased at the time of death, or the donor at the time of the gift, is a resident or citizen of Norway. However, if a Norwegian citizen is not a resident of Norway at the time of his or her death, Norwegian inheritance tax will not be levied if an inheritance tax or a similar tax is levied by the country of residence. Irrespective of citizenship, Norwegian inheritance tax may be levied if the shares or ADSs are effectively connected with the conducting of a trade or business through a permanent establishment in Norway.

Taxation on the realisation of shares

Under the participation exemption model, corporate shareholders resident in Norway for tax purposes are exempt from tax on gains on the disposal of shares. However, effective from 7 October 2008 3% of net income that is tax free under the participation exemption will be included in the Norwegian corporate shareholder's general taxable income. Costs directly related to the acquisition and sale of such shares are not deductible for tax purposes. Corporate shareholders will not be allowed a deduction for losses incurred on the sale, swap or redemption of shares if a gain would be exempted from taxation.

For individual shareholders resident in Norway for tax purposes, the sale, redemption or other disposal of shares will be considered a taxable realisation of shares. Gains or losses in connection with such realisation are included in or deducted from the individual's general taxable income in the year of disposal. Ordinary income is taxed at a flat rate of 28%. The gain is subject to tax and the loss is deductible irrespective of the length of the ownership and the number of shares disposed of.

The taxable gain or loss is calculated as the sales price adjusted for transaction expenses minus the taxable basis. A shareholder's tax basis is normally equal to the acquisition cost of the shares. Any unused "deductible allowance" from previous years attributable to the individual shares realised may be deducted.

Shareholders not resident in Norway are generally not subject to tax in Norway on capital gains, and losses are not deductible on the sale, redemption or other disposal of shares or ADSs in Norwegian companies, unless the shareholder is carrying on business activities in Norway and such shares or ADSs are or have been effectively connected with such activities. In addition, individual shareholders previously resident in Norway may on certain conditions be liable to tax in Norway for such gains if the realisation takes place within five years of the end of the calendar year in which the shareholder ceased to be a resident of Norway for tax purposes, or, alternatively, within five years of the Norwegian tax residency expiring pursuant to Norwegian domestic law or tax treaty.

Transfer tax. No transfer tax is imposed in Norway in connection with the sale or purchase of shares.

United States tax matters

This section describes the material United States federal income tax consequences for US holders (as defined below) of owning shares or ADSs. It only applies to you if you hold your shares or ADSs as capital assets for tax purposes. This section does not apply to you if you are a member of a special class of holders subject to special rules, including:

- dealers in securities;
- traders in securities that elect to use a mark-to-market method of accounting for their securities holdings;
- tax-exempt organisations;
- life insurance companies;
- persons liable to alternative minimum tax;
- persons that actually or constructively own 10% or more of the voting stock of StatoilHydro;
- persons that hold shares or ADSs as part of a straddle or a hedging or conversion transaction; or
- persons whose functional currency is not USD.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations, published rulings and court decisions, and the Convention between the United States of America and the Kingdom of Norway for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with Respect to Taxes on Income and Property (the "Treaty"). These laws are subject to change, possibly on a retroactive basis. In addition, this section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms. For United States federal income tax purposes, if you hold ADRs evidencing ADSs, you will generally be treated as the owner of the ordinary shares represented by those ADRs. Exchanges of shares for ADRs, and ADRs for shares will not generally be subject to United States federal income tax.

You are a "US holder" if you are a beneficial owner of shares or ADSs and you are for United States federal income tax purposes:

- an individual who is a citizen or resident of the United States;
- a United States domestic corporation;
- an estate whose income is subject to United States federal income tax regardless of its source; or
- a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorised to control all substantial decisions of the trust.

You should consult your own tax advisor regarding the United States federal, state and local and other tax consequences of owning and disposing of shares and ADSs in your particular circumstances.

Taxation of dividends. Subject to the passive foreign investment, or PFIC, rules discussed below, if you are a US holder, the gross amount of any dividend paid by StatoilHydro of its current or accumulated earnings and profits (as determined for United States federal income tax purposes) is subject to United States federal income taxation. If you are a non-corporate US holder, dividends paid to you in taxable years beginning before 1 January 2011 that constitute qualified dividend income will be taxable at a maximum tax rate of 15% if you hold the shares or ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet other holding-period requirements. Dividends we pay with respect to shares or ADSs will generally be qualified dividend income.

You must include any Norwegian tax withheld from the dividend payment in this gross amount even though you do not in fact receive the amount withheld as tax. The dividend is taxable to you when you, in the case of shares, or the depositary, in the case of ADSs, receive the dividend, actually or constructively. The dividend will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations.

The amount of the dividend distribution that you must include in your income as a US holder will be the value in US dollars (USD) of the payments made in Norwegian kroner (NOK) determined at the spot NOK/USD rate on the date the dividend distribution is included in your income, regardless of whether or not the payment is in fact converted into US dollars. Distributions in excess of current and accumulated earnings and profits, as determined for United States federal income tax purposes, will be treated as a non-taxable return of capital to the extent of your tax basis in the shares or ADSs and, to an extent in excess of your tax basis, will be treated as capital gain.

Subject to certain limitations, the 15% Norwegian tax withheld in accordance with the Treaty and paid to Norway will be creditable against your United States federal income tax liability. Special rules apply when determining the foreign tax credit with respect to dividends that are subject to the maximum 15% rate. Dividends will be income from sources outside the United States. Dividends paid in taxable years beginning before 1 January 2007 will generally be "passive income" or "financial services income", and dividends paid in taxable years beginning after 31 December 2006 will, depending on your circumstances, be "passive" or "general" income, which, in either case, is treated separately from other types of income for purposes of computing the foreign tax credit allowable to you.

Any gain or loss resulting from currency exchange rate fluctuations during the period from the date you include the dividend payment in income until the date you convert the payment into US dollars will generally be treated as ordinary income or loss and will not be eligible for the special tax rate applicable to qualified dividend income. Such gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

Taxation of capital gains. Subject to the PFIC rules discussed below, if you are a US holder and you sell or otherwise dispose of your shares or ADSs, you will generally recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the value in US dollars of the amount that you realise and your tax basis, determined in US dollars, in your shares or ADSs. A capital gain by a non-corporate US holder that is recognised before 1 January 2011 is generally taxed at a maximum rate of 15% if the holding period of the holder is longer than one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes.

If you receive any foreign currency on the sale of shares or ADSs, you may recognise ordinary income or loss from sources within the United States as a result of currency fluctuations between the date of the sale of the shares or ADSs and the date the sales proceeds are converted into US dollars.

PFIC Rules. We believe that the shares and ADSs should not be treated as stock of a PFIC for United States federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If we were to be treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to the shares or ADSs, a gain realised on the sale or other disposition of the shares or ADSs would in general not be treated as a capital gain. Instead, if you are a US holder, you would be treated as if you had realised such gain and certain "excess distributions" ratably over your holding period for the shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, the shares or ADSs will be treated as stock in a PFIC if we were a PFIC at any time during the period you held the shares or ADSs. Dividends that you receive from us will not be eligible for the special tax rates applicable to qualified dividend income if we are treated as a PFIC with respect to you, either in the taxable year of the distribution or the preceding taxable year, but will instead be taxable at rates applicable to ordinary income.

6.7 Exchange controls and other limitations

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior government approval except for the physical transfer of payments in currency, which is restricted to licensed banks.

This means that non-Norwegian resident shareholders may receive dividend payments without Norwegian exchange control consent as long as the payment is made through a licensed bank.

There are presently no restrictions affecting the rights of non-residents or foreign owners to hold or vote our shares.

6.8 Exchange rates

The table below shows the high, low, average and end-of-period noon buying rates in the City of New York for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York for Norwegian kroner per USD 1.00. The average is computed using the noon buying rate on the last business day of each month during the period indicated.

Year ended December 31	Low	High	Average	End of Period
2004	6.0551	7.1408	6.7241	6.0794
2005	6.0667	6.8023	6.4591	6.7444
2006	5.9869	6.8490	6.3582	6.2287
2007	5.2619	6.4728	5.8109	5.4310
2008	**4.9467**	**7.2848**	**5.6773**	**6.9756**

	Low	High
2008		
September	5.4948	5.9307
October	5.8833	7.0680
November	6.5930	7.2169
December	6.6216	7.2848
2009		
January	6.6827	7.2087
February	6.6179	7.0474
March (up to and including 6 March 2009)	7.0479	7.2778

On 6 March 2009 the noon buying rate for Norwegian kroner was USD 1.00 = 7.0612 NOK.

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

7 Corporate governance

The objective of StatoilHydro is to create long-term value for its shareholders through exploration, production, transportation, refining and marketing of petroleum and petroleum derived products.

In pursuing our corporate objective, we are committed to the highest level of governance and to cultivating a value-based performance culture that rewards exemplary ethical standards, respect for the environment and personal and corporate integrity. We believe that there is a link between high-quality governance and the creation of shareholder value.

The work of the board of directors is based on the existence of a clearly-defined division of roles and responsibilities between the shareholders, the board of directors and the management in StatoilHydro

Our governing structures and controls help to ensure that we run our business in a profitable manner to the benefit of our shareholders, employees and other stakeholders in societies in which we operate.

The following principles underline our approach to corporate governance:

- All shareholders will be treated equally
- StatoilHydro will ensure that all shareholders have access to up-to-date, reliable and relevant information about the company's activities
- StatoilHydro will have a board of directors that is independent of the group's management. The board focuses on there not being any conflicts of interest between owners, the board of directors and the company's management
- The board of directors will base its work on the principles for good corporate governance applicable at all times

Corporate governance in StatoilHydro is subject to annual reviews and discussions by the corporate board of directors.

StatoilHydro's board of directors endorses the 'Norwegian Code of Practice for Corporate Governance', last revised 4 December 2007. The company's compliance with and, if applicable, deviation from the Code of Practice is commented on and these comments made available.

Compliance with NYSE listing standards

StatoilHydro is a public limited company with a governance structure based on Norwegian law. StatoilHydro's primary listing is on the Oslo stock exchange (Oslo Børs). The group is also registered with the US Securities and Exchange Commission and listed on the New York Stock Exchange (NYSE). As a consequence, StatoilHydro is required to disclose any significant ways in which its corporate governance practices differ from those applicable to US companies under the NYSE listing standards. A statement of difference, pursuant to Rule 303A.11 of the NYSE Listed Company Manual, is set out below.

Committees

NYSE rules applicable to US companies require that there be certain board committees composed of independent directors with responsibility for certain matters.

In accordance with Norwegian law, managing the company is the responsibility of the board of directors.
StatoilHydro has an audit committee and a compensation committee (called remuneration committee), which are responsible for preparing certain issues for the board of directors.

The committees operate pursuant to charters that are broadly comparable to the form required by the NYSE rules.

The committees report on a regular basis to and are subject to continuous oversight by the board of directors.

The membership of StatoilHydro's audit committee includes one employee-elected director, who meets the requirements for independence under Rule 10A-3(b)(1) of the US securities Exchange Act of 1934, but would not be considered independent for purposes of the NYSE rules.

Among other things, the audit committee evaluates the qualifications and independence of the company's external auditor. However, in accordance with Norwegian law, the auditor is elected by the annual general meeting of the company's shareholders.

StatoilHydro does not have a nominating/corporate governance committee. Instead, the roles prescribed for a nominating/corporate governance committee under the NYSE rules are principally carried out by the corporate assembly and the election committee.

StatoilHydro's corporate governance principles are developed by management and the board of directors.
Oversight of the board of directors and management is carried out by the corporate assembly.

Independence

StatoilHydro's board of directors consists of members elected by shareholders and employees, none of whom are executive officers of the company.

The directors elected among StatoilHydro's employees would not be considered "independent", as defined under NYSE Rule 303A.02, but are independent for the purposes of Rule 10A-3(b)(1) of the US securities Exchange Act of 1934, which applies to members of the company's audit committee.

The NYSE rules require that the board of directors must affirmatively determine that each "director has no material relationship with the listed company."

StatoilHydro's board of directors has determined that, in its judgement, all of the shareholder-elected directors are independent.

Shareholder approval of equity compensation plans
The NYSE rules require that all equity compensation plans, with limited exemptions, must be subject to shareholder vote.

Although issuance of shares and authority to buy back company shares must be approved by StatoilHydro's annual general meeting of shareholders under Norwegian company law, approval of equity compensation plans is normally reserved for the board of directors.

7.1 Ethics Code of Conduct

Together with StatoilHydro's values statement, the Ethics Code of Conduct constitutes the basis and framework for our performance culture and governance system.

Our ability to create value is dependent on high ethical standards, and we are determined that StatoilHydro shall be known for these. 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.

The StatoilHydro Ethics Code of Conduct describes the requirements which apply to our business practice.

The Code's target group is all employees, the chief executive officer, chief financial officer, controller and members of the board of directors of StatoilHydro and its subsidiaries. The Ethics Code of Conduct is accessible at www.statoilhydro.com/en/AboutStatoilHydro/EthicsValues/Pages/ethics.aspx

Business partners are also expected to have ethical standards that are compatible with StatoilHydro's standards.

StatoilHydro has a dedicated ethics helpline that may be used by employees or any person that wants to express concerns or seek advice regarding the legal and ethical conduct of StatoilHydro's business.

7.2 Articles of association

The Articles of Association and the Norwegian Public Limited Companies Act form the legal framework for StatoilHydro's operations.

StatoilHydro's Articles of Association were adopted at the Extraordinary General Meeting of 5 July 2007:

Summary of our Articles of Association
Name of the Company
Our registered name is StatoilHydro ASA. We are a Norwegian public limited company.

Registered office
Our registered office is in Stavanger, Norway, registered with the Norwegian Register of Business Enterprises under number 913 609 016.

Object of the company
The object of our company is, either by us or through participation in or together with other companies, to carry out exploration, production, transportation, refining and marketing of petroleum and petroleum derived products, as well as other businesses.

Share capital
Our share capital is NOK 7,971,617,757.50 divided into 3,188,647,103 ordinary shares.

Nominal value of shares
The nominal value of each ordinary share is NOK 2.50.

Board of directors
Our articles of association provide that our board of directors shall be composed of ten directors. The board, including the chair and the deputy chair, shall be elected by the Corporate Assembly.

Corporate Assembly
We have a corporate assembly of 18 members who are elected for two-year terms. The general meeting elects 12 members with four alternates and six members with alternates are elected by and among the employees.

Annual general meeting
Our annual general meeting is held no later than June 30 each year upon at least two weeks' written notice.

The meeting will deal with the Annual Report and accounts, including distribution of dividends, and any other matters as required by law or our articles of association.

Marketing of petroleum on behalf of the Norwegian State
Our articles of association provide that we are responsible for marketing and selling petroleum produced under the SDFI's shares in production licenses on the NCS as well as petroleum received by the Norwegian State as royalty together with our own production. Our general meeting adopted an instruction in respect of such marketing on 25 May 2001.

Nomination Committee
The general meeting decided to amend our articles of association on 7 May 2002 in order to establish a nomination committee (in the articles of association referred to as the 'election committee'). The tasks of the election committee are to make recommendations to the general meeting regarding the election of and fees to shareholder-elected members and deputy members of the corporate assembly, and to make recommendations to the corporate assembly regarding the election of and fees to shareholder-elected members and deputy members of the board of directors.

The full Articles of Association can be found at
http://www.statoilhydro.com/en/aboutstatoilhydro/corporategovernance/articlesofassociation/pages/default.aspx

7.3 General meeting of Shareholders

The annual general meeting of shareholders (AGM) is the company's supreme body. The objective of the general meeting is to ensure shareholder democracy, and StatoilHydro encourages all shareholders to participate in person or by proxy.

Shareholders who are unable to attend the general meeting in person may follow the proceedings by webcast. The business of the AGM is conducted in Norwegian and translated simultaneously into English.

Pursuant to StatoilHydro's articles of association and the Norwegian Public Limited Companies Act, the AGM:

- Elects the shareholders' representatives to the corporate assembly
- Elects the nomination committee (referred to as the election committee in the articles of association)
- Elects the external auditor and stipulates the auditor's fee
- Approves the board of directors' report in accordance with Norwegian requirements, the financial statements and the dividend, proposed by the board of directors and recommended by the corporate assembly
- Deals with any other matters listed in the notice convening the meeting

Pursuant to the company's articles of association, the AGM must be held by the end of June each year.

Notice of the meeting and documents for the AGM are published on StatoilHydro's website together with the annual report and are sent by mail to the shareholders. Documentation from previous AGMs is available on StatoilHydro's website.

All shareholders are entitled to have their proposal discussed at the annual general meeting, if the proposal has been submitted in writing to the board of directors in due time to either be included in distributed notice of meeting or in a new notice of meeting to be distributed no later than two weeks before the general meeting is to be held. As a general rule, the general meeting cannot discuss matters that are not listed in the notice of meeting.

All shareholders who are registered in the Norwegian Central Securities Depository (VPS) will receive an invitation to the AGM. They are entitled to submit proposals and vote, in person or by proxy. The deadline for registration is four days prior to the AGM.
The chair of the AGM will normally be 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.

Given the large number of shareholders and their wide geographical distribution, the number of shareholders who are able to attend the AGM in person will be limited. StatoilHydro therefore offers its shareholders an opportunity to follow the proceedings by webcast. The business of the AGM is conducted in Norwegian and translated simultaneously into English.

All of our ordinary shares carry an equal right to vote at general meetings. Except as otherwise provided, decisions which shareholders are entitled to make pursuant to Norwegian law or our articles of association may be made by a simple majority of the votes cast. In the case of elections, the persons who obtain the most votes cast are deemed elected. However, certain decisions, including resolutions to waive preferential rights in connection with any share issue, to approve a merger or demerger, to amend our articles of association or to authorise an increase or reduction in our share capital, must receive 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 a shareholders' meeting.

If we issue any new shares, including bonus share issues, our articles of association must be amended, which requires the same vote as other amendments to our articles of association. In addition, under Norwegian law, our shareholders have a preferential right to subscribe to issues of new shares by us. The preferential rights to subscribe to an issue may be waived by a resolution in a general meeting passed by the same percentage threshold required to approve amendments to our articles of association. The general meeting may, with a vote as described above, authorize the board of directors to issue new shares, and to waive the preferential rights of shareholders in connection with such issuances. Such authorization may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the nominal share capital when the authorization was granted.

The issuance of shares to holders who are citizens or residents of the United States upon the exercise of preferential rights may require us to file a registration statement in the United States under United States securities laws. If we decide not to file a registration statement, these holders may not be able to exercise their preferential rights.

Rights of Redemption and Repurchase of Shares
Our articles of association do not authorize the redemption of shares. In the absence of authorization, the redemption of shares may still be decided by a general meeting of shareholders by a two-thirds majority under certain conditions. However, the share redemption would, for all practical purposes, depend on the consent of all shareholders whose shares are redeemed.

A Norwegian company may purchase its own shares if an authorization to do so has been given by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast as well as two thirds of the share capital represented at the general meeting. The aggregate par value of treasury shares held by the company must not exceed 10% of the company's share capital and treasury shares may only be acquired if the company's distributable equity, according to the latest adopted balance sheet, exceeds the consideration to be paid for the shares. The authorization by the general meeting cannot be given for a period exceeding 18 months.

Distribution of Assets on Liquidation
Under Norwegian law, a company may be wound-up by a resolution of the company's shareholders in a general meeting passed by both a two-thirds majority of the aggregate votes cast and two-thirds of the aggregate share capital represented at the general meeting. The shares rank equal in the event of a return on capital by the company upon a winding-up or otherwise.

Electronic voting
StatoilHydro intends to make use of electronic voting at its general meetings as soon as Norwegian legislation allows this.

Extraordinary general meetings
Pursuant to Norwegian law, the corporate assembly, the chair of the corporate assembly, the auditor, or shareholders representing at least 5% of the share capital, may demand that an extraordinary general meeting be held in order to have a specific matter considered and decided. The board must ensure that the extraordinary general meeting is held within a month of such a demand being submitted.

7.4 Board of directors

Pursuant to StatoilHydro's articles of association, the board of directors consists of 10 members. The management is not represented on the board. A majority of the members of the board are deemed to be 'independent' board members.

As required by Norwegian company law, the company's employees are entitled to be represented by three board members. There are no board member service contracts that provide for benefits upon termination of office. The StatoilHydro board has determined that, in its judgment, all of the non-employee directors are independent. In doing so, however, the board did not explicitly take into consideration the NYSE's five specific tests.

The board of directors of StatoilHydro ASA is responsible for the overall management of the StatoilHydro 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 board of directors has two sub-committees, the audit committee and the compensation committee.

The board held 13 meetings in 2008. Attendance at board meetings was 97%.

Members of the board of directors

Svein Rennemo.

Svein Rennemo
Position: Chair of the board and member of the board's compensation committee.
Born: 1947
Term of office: Member of the board of StatoilHydro ASA since 1 April 2008
Independent: Yes
Other directorships: Chair of the board of Integrated Optoelectronics AS and Pharmaq AS Member of the board of Norske Skogindustrier ASA.
Number of shares in StatoilHydro ASA pr. 31. December 2008: 10,000
Loans from StatoilHydro: None
Experience: CEO of Petroleum Geo Services ASA from 2002 until 1 April 2008 (when he took up office as chair of the board of StatoilHydro)
From 1994 to 2001, Mr Rennemo worked for Borealis, first as Deputy CEO and CFO and from 1997 as CEO.
He held various management positions in Statoil from 1982 to 1994, latterly as head of the petrochemical division.
During the period 1972 to 1982, he was an analyst and monetary policy and economics advisor with Norges Bank (the Norwegian central bank), the OECD Secretariat in Paris and the Ministry of Finance.
Education: Economist from the University of Oslo.
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly.
Other matters: Svein Rennemo is a Norwegian citizen, and he lives in Norway.

Marit Arnstad.

Marit Arnstad
Position: Deputy chair and member of the board's audit committee.
Born: 1962
Term of office: Member of the board of Statoil ASA from June 2006 and member of the board of StatoilHydro ASA since 1 October 2007
Independent: Yes
Other directorships: Chair of the board of the Norwegian University of Science and Technology (NTNU). Board member of Adresseavisen ASA, NTE Nett AS, Aker Seafood ASA and Acta ASA.
Number of shares in StatoilHydro ASA pr. 31. December 2008: 0
Loans from StatoilHydro: None
Experience: Ms Arnstad is an advocate with the law firm Schjødt AS.
Ms Arnstad was Minister of Petroleum and Energy during the period 1997 - 2000. She was a member of the Norwegian parliament, the Storting, for the Centre Party from 1993 to 1997 and 2001 to 2005, and was leader of the party's parliamentary group from 2003 to 2005. Before this, she was a Higher Executive Officer at the Ministry of the Environment.
Education: Law graduate (cand. jur.) from the University of Oslo.
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Marit Arnstad is a Norwegian citizen, and she lives in Norway.

Kjell Bjørndalen.

Kjell Bjørndalen
Position: Board member and member of the board's compensation committee.
Born: 1946
Term of office: Member of the board of StatoilHydro ASA since 1 October 2007. Member of Statoil ASA's corporate assembly from 1992 to 2007.
Independent: Yes
Other directorships: Mr Bjørndalen is a member of the boards of Alfred Berg Kapitalforvaltning AS, Xynergo AS and Bank 1 Oslo.
Number of shares in StatoilHydro ASA pr. 31. December 2008: 0
Loans from StatoilHydro: None
Experience: Until October 2007, he was president of the Norwegian United Federation of Trade Unions (Fellesforbundet) and a member of the secretariat of the Norwegian Confederation of Trade Unions (LO).
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly.
Other matters: Kjell Bjørndalen is a Norwegian citizen, and he lives in Norway.

Roy Franklin.

Roy Franklin
Position: Member of the board, and the board's audit committee.
Born: 1953
Term of office: Member of the board of StatoilHydro ASA since 1 October 2007
Independent: Yes
Other directorships: Chair of Brindex, the Association of British Independent Oil Exploration Companies, and a member of the joint British oil industry and government task force Pilot from 2002 to 2005.
He is non-executive chair of the boards of Bateman Litwin NV, Novera Energy Ltd, a leading UK company in the field of renewable energy, TS Marine Ltd, based in Aberdeen and Keller Group plc, a London-based international engineering company. Board member of the Australian oil and gas company Santos Ltd.
Number of shares in StatoilHydro ASA pr. 31. December 2008: None
Loans from StatoilHydro: None
Experience: Has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc.
Education: Bachelor of Science in geology from the University of Southampton in the UK.
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly.
Other matters: Roy Franklin is a UK citizen and he lives in the UK.
In 2004, he was awarded an OBE for his work for the British oil and gas industry.

Elisabeth Grieg.

Elisabeth Grieg
Position: Board member and member of the board's compensation committee.
Born: 1959
Term of office: Member of the board of Norsk Hydro ASA from 2001 to 2007 and member of the board of StatoilHydro ASA since 1 October 2007.
Independent: Yes
Other directorships: Chair of the board of Grieg Shipping Group and Grieg Star Shipping AS. Board member in Grieg Maturitas AS, Grieg Foundation and SOS Children's Villages, Norway. Member of the corporate assembly and election committee of Orkla ASA, and of the council of Det Norske Veritas.
Number of shares in StatoilHydro ASA pr. 31. December 2008: 33,108
Loans from StatoilHydro: None
Experience: Managing Director of Grieg International AS and co-owner of the Grieg Group. President of the Norwegian Shipowners' Association
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Elisabeth Grieg is a Norwegian citizen, and she lives in Norway.
Elisabeth Grieg is part-owner of the family company Grieg Maturitas AS, which indirectly owns 20% of AON Grieg AS. AON Grieg AS acted as broker for StatoilHydro in 2008 and received fees totalling NOK 16,934,611 from StatoilHydro in 2008.
In addition, Grieg Maturitas AS and other family companies own a direct and indirect interest of 75% of Grieg Logistics AS. Elisabeth Grieg's husband, Stig Grimsgaard Andersen, is a board member of Grieg Logistics AS. Grieg Logistics AS delivered logistics and transport services to StatoilHydro in 2008, for which it received fees totalling NOK 135,177,387.

Kurt Anker Nielsen.

Kurt Anker Nielsen
Position: Board member and chair of the board's audit committee.
Born: 1945
Term of office: Member of the board of Norsk Hydro ASA from 2004 to 2007 and member of the board of StatoilHydro since 1 October 2007
Independent: Yes
Other directorships: Mr Nielsen is chair of the board of Reliance A/S and deputy chair of the board of Novozymes A/S. He is a board member of Novo Nordisk A/S, Novo Nordisk Fonden, ZymoGenetics Inc, Vestas Wind Systems A/S and Life Cycle Pharma A/S
Number of shares in StatoilHydro ASA pr. 31. December 2008: 0
Loans from StatoilHydro: None
Experience: Kurt Anker Nielsen has held senior management positions in Novo A/S and Novo Nordisk A/S in Denmark, including the positions of CFO and managing director.
Education: MSc (Economics and Business Administration), Copenhagen Business School.
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Kurt Anker Nielsen is a Danish citizen and he lives in Denmark

Grace Reksten Skaugen.

Grace Reksten Skaugen
Position: Board member and member of the board's compensation committee
Born: 1953
Term of office: Member of the board of Statoil from 2002 and a member of the board of StatoilHydro from 1 October 2007
Independent: Yes
Other directorships: Chair of the boards of Entra Eiendom AS and Ferd Holding and member of the board of the Swedish listed company Investor AB
Number of shares in StatoilHydro ASA pr. 31. December 2008: 400
Loans from StatoilHydro: None
Experience: Self-employed consultant, director within Corporate Finance in Enskilda Securities in Oslo from 1994 to 2002. Has also worked with venture capital and shipping in Oslo and London and carried out research in microelectronics at Columbia University in New York
Education: She has a doctorate in laser physics from the Imperial College of Science and Technology at the University of London and an MBA from the Norwegian School of Management (BI)
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Grace Reksten Skaugen is a Norwegian citizen and she lives in Norway

Lill-Heidi Bakkerud.

Lill-Heidi Bakkerud
Position: Represents the employees on the board.
Born: 1963.
Term of office: Member of the board of Statoil ASA from 1998 to 2002 and from 2004 to 2007. Member of the board of StatoilHydro ASA since 1 October
Independent: No
Other directorships: She is a member of the executive committee of the Industry Energy (IE) trade union and holds a number of offices as a result of this
Number of shares in StatoilHydro ASA pr. 31. December 2008: 330
Loans from StatoilHydro: None
Experience: She has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is now a full-time employee representative as leader of the StatoilHydro branch of IE.
Education: Has a craft certificate as a process/chemistry worker
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Lill-Heidi Bakkerud is a Norwegian citizen, and she lives in Norway

Claus Clausen.

Claus Clausen
Position: Represents the employees on the board
Born: 1954
Term of office: Member of the board of Statoil ASA from 2006 to 2007 and StatoilHydro ASA since 1 October 2007
Independent: No
Other offices: None
Number of shares in StatoilHydro ASA pr. 31. December 2008: 165
Loans from StatoilHydro: None
Experience: Mr Clausen worked for Statoil from 1991, and from 1997 he held various positions in the process discipline. He was attached to Statfjord from 2001, among other things as process discipline manager. Mr Clausen is currently head of inspection and surface maintenance in Stavanger
Education: Claus Clausen has an engineering degree from Bergen Engineering College
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Claus Clausen is a Norwegian citizen, and he lives in Norway

Morten Svaan.

Morten Svaan
Position: Represents the employees on the board and is a member of the board's audit committee
Born: 1956
Term of office: Member of the board of Statoil ASA from 2002 to 2007 and of StatoilHydro ASA since 1 October 2007
Independent: No
Other directorships: None
Number of shares in StatoilHydro ASA pr. 31. December 2008: 933
Loans from StatoilHydro: NOK 260,555. This is a car loan in the company on the terms and conditions that apply to all employees at his job level
Experience: Mr Svaan worked for Statoil from 1985. He now works on health, safety and the environment (HSE) for the Technology & New Energy business area, largely focusing on security and emergency response. Mr Svaan was chief employee representative for the Statoil branch of the NIF/Tekna union from 2000 until 2004.
Education: He has a PhD in chemistry from the Norwegian University of Science and Technology and a degree in business economics from the Norwegian School of Management (BI)
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Morten Svaan is a Norwegian citizen, and he lives in Norway

The following two persons are employee-elected observer on the board, with no voting rights

Ragnar Fritsvold.

Ragnar Fritsvold
Position: An employee-elected observer on the board
Born: 1948
Term of office: Member of the board of Norsk Hydro ASA from May 2007 until October 2007. Observer on the board of StatoilHydro ASA since 1 October 2007
Independent: No
Other directorships: None
Number of shares in StatoilHydro ASA pr. 31. December 2008: 468
Experience: Mr Fritsvold joined Hydro in 1979, and he is now a staff engineer in StatoilHydro and a full-time employee representative. He was leader of the Hydro branch of the Norwegian Society of Graduate Technical and Scientific Professionals (Tekna) from 1999 to 2007.
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Ragnar Fritsvold is a Norwegian citizen, and he lives in Norway

Geir Nilsen.

Geir Nilsen
Position: Employee-elected observer on the board. Represents employees who are members of the Norwegian Confederation of Trade Unions (LO)
Born: 1955
Term of office: Member of the board of Norsk Hydro ASA from 2003 to 2007. Observer on the board of StatoilHydro since 1 October 2007
Independent: No
Other directorships: None
Number of shares in StatoilHydro ASA pr. 31. December 2008: 626
Experience: Joined Hydro in 1973 and worked as a maintenance manager in Petrochemicals/PVC from 1984 to 1988. Employed offshore from 1988, as a maintenance manager from 1996
Education: Automation worker
Family relations: No family relations to other members of the Board, members of the Corporate Executive Committee or the Corporate Assembly
Other matters: Geir Nilsen is a Norwegian citizen, and he lives in Norway

7.4.1 Audit committee

The board elects up to four of its members to serve on the audit committee. The current members of the audit committee are Kurt Anker Nielsen (chair), Marit Arnstad, Roy Franklin and Morten Svaan.

The audit committee is a sub-committee of the board of directors and its objective is to carry out more thorough assessments of specific matters in the StatoilHydro group and report to the board of directors. The audit committee is instructed to assist the board in its supervising of issues such as:

(1) the quality and integrity of the company's financial statements and related disclosures
(2) the external auditor's qualifications and independence
(3) the performance of the external auditor pursuant to the requirements of Norwegian law and the laws of those countries where the company is listed on the stock exchange
(4) the performance of the company's internal audit function, internal controls and risk management systems
(5) the company's compliance with legal and regulatory requirements, including the requirements relating to listing on stock exchanges and
(6) compliance with the group's ethical rules, including the group's compliance activities relating to corruption.

The internal audit function reports directly to the board of directors and to the chief executive officer. The audit committee assists the board in overseeing this function. The audit committee also receives regular briefings and reports on internal control and ethical issues.

Under Norwegian law, our external auditor is elected by our shareholders at the annual general meeting. The audit committee makes a recommendation to the board of directors for the appointment of the external auditor based on its evaluation of the qualifications and independence of the auditor proposed for election or re-election. The audit committee meets at least six times a year, and it meets separately with the internal auditor and the external auditor on a regular basis.

The audit committee is also charged with reviewing the scope of the audit and the nature of any non-audit services provided by external auditors. The external auditors report directly to the audit committee on a regular basis. The audit committee also has procedures for receiving and dealing with complaints received by the company regarding accounting, internal controls or auditing matters and for the confidential, anonymous submission by employees of the company of concerns regarding accounting or auditing matters. The audit committee has the authority to engage independent advisers to assist it in carrying out its duties.

The audit committee held 8 meetings in 2008. There was 97 % attendance at the committee's meetings.

The committee's mandate is available at
http://www.statoilhydro.com/en/AboutStatoilHydro/CorporateGovernance/GoverningBodies/AuditCommittee/Pages/default.aspx

7.4.1.1 Audit committee financial expert

The board of directors has decided that a member of the audit committee, Kurt Anker Nielsen, qualifies as an "audit committee financial expert", as defined in Item 16A of Form 20-F.

The board of directors has also concluded that Kurt Nielsen is independent in accordance with the meaning of Rule 10A-3 under the Securities Exchange Act.

7.4.1.2 Exemptions from listing standards

This section describes an exemption from the listing standards for audit committees that StatoilHydro relies upon.

StatoilHydro relies on the exemption provided in Rule 10A-3(b)(1)(iv)(C) from the independence requirements of the Securities Exchange Act with respect to Morten Svaan, a member of the audit committee who is also one of three members of the board of directors of StatoilHydro elected by the employees in accordance with Norwegian company legislation. Mr Svaan is a non-executive employee of the company.

StatoilHydro does not believe that its reliance on this exemption will materially adversely affect the ability of the audit committee to act independently or to satisfy the other requirements of Rule 10A-3 relating to audit committees.

7.4.2 Compensation committee

The compensation committee is a sub-committee of the board of directors that assists the board of directors on matters relating to management compensation and leadership development.

The compensation committee is a sub-committee of the board of directors and the main responsibilities are:

(1) as a preparatory body for the board, make recommendations to the board in all matters relating to executive reward principles, remuneration strategies and concepts, the CEO's contract and terms of employments and leadership development, assessments and succession planning

(2) to be informed about and advise the company's management in its work on StatoilHydro's remuneration strategy and in drawing up appropriate remuneration policies and

(3) to review StatoilHydro's remuneration policies in order to safeguard the owners' long-term interests.

The committee consists of four board members. At year end 2008, the committee members were Grace Reksten Skaugen (chair), Svein Rennemo, Elisabeth Grieg and Kjell Bjørndalen.
All of the committee members are independent, non-executive directors.

The committee held 6 meetings in 2008. There was 95 % attendance at the committee's meetings.

The committee's mandate is accessible at
http://www.statoilhydro.com/en/AboutStatoilHydro/CorporateGovernance/GoverningBodies/BoardsCompensationCommittee/Pages/default.aspx

7.5 Corporate assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, companies with more than 200 employees must elect a corporate assembly unless otherwise agreed between the company and a majority of its employees.

The corporate assembly must be composed of at least 12 members or a larger quantity divisible by three. Shareholders elect two-thirds of the members to the corporate assembly while employees elect the remaining one-third.

Pursuant to StatoilHydro's articles of association, our corporate assembly consists of 18 members. Twelve memebers and four alternates are elected at the general meeting by the shareholders, and six members are elected by and among the employees, such employees being non-executives.

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

The corporate assembly's main duty is to elect the board of directors.

Its responsibilities also include overseeing the board and CEO's management of the company, making decisions on investments of considerable magnitude in relation to the company's resources and making decisions involving the rationalisation or reorganisation of operations that will entail major changes in or reallocation of the workforce.

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

The corporate assembly held 5 meetings in 2008.

The following is a list of the members of the corporate assembly as of 31 December 2008:

Name	Occupation	Place of Residence	Year of birth	Position	Family relations to Corporate Executive committee, Assembly members	Share ownership for members	First time elected	Expiration date of current term
Olaug Svarva	Managing Director, Folketrygdfondet	Oslo	1957	Chair, Shareholder elected	No	0	2007	2010
Idar Kreutzer	CEO, Storebrand	Oslo	1962	Deputy chair, Shareholder elected	No	0	2007	2010
Karin Aslaksen	Senior Vice President, Elkem AS	Hosle	1959	Shareholder elected	No	0	2008	2010
Greger Mannsverk	Managing Director, Bergen Group Kimek	Kirkenes	1961	Shareholder elected	No	0	2002	2010
Steinar Olsen	Self-employed	Stavanger	1949	Shareholder elected	No	0	2007	2010
Benedicte Berg Schilbred	Working Chair of the Board, Odd Berg Group	Tromsø	1946	Shareholder elected	No	0	2007	2010
Ingvald Strømmen	Dean, NTNU	Ranheim	1950	Shareholder elected	No	0	2006	2010
Inger Østensjø	Chief administrative officer, Stavanger Municipality	Stavanger	1954	Shareholder elected	No	0	2006	2010
Rune Bjerke	CEO, DnBNOR	Oslo	1960	Shareholder elected	No	0	2007	2010
Gro Brækken	Secretary General, Save the Children	Snarøya	1952	Shareholder elected	No	0	2007	2010
Kåre Rommetveit	Director, Bergen Medical research foundation	Hjellestad	1945	Shareholder elected	No	0	2007	2010
Tore Ulstein	Managing Director, Ulstein International	Ulsteinvik	1967	Shareholder elected	No	0	2008	2010
Anne Synnøve Hebnes	Manager,Technology & New Energy	Stavanger	1972	Employee representative	No	0	2006	2009
Per Helge Ødegård	Union Official, Exploration & Production Norway	Porsgrunn	1963	Employee representative	No	964	1994	2009
Arvid Færaas	Manager, Natural Gas	Vormedal	1962	Employee representative	No	344	2000	2009
Einar Arne Iversen	Union Official, Corporate Staff & Services	Molde	1962	Employee representative	No	1,512	2000	2009
Tore Amund Fredriksen	Principal engineer, Technology & New Energy	Porsgrunn	1953	Employee representative	No	826	2007	2009
Per Martin Labråthen	Process technician, Exploration & Production Norway	Brevik	1961	Employee representative	No	129	2007	2009
Jan-Eirik Feste	Union Official, Marketing & Manufacturing	Lindås	1952	Employee representative, observer	No	130	2008	2009
Anne K.S. Horneland	Union Official, Exploration & Production Norway	Hafrsfjord	1956	Employee representative, observer	No	1,760	2006	2009

All members of the corporate assembly reside in Norway. Members of the corporate assembly do not have service contracts with the company or its subsidiaries providing for benefits upon termination of employment.

7.6 Management

The president and CEO has overall responsibility for day-to-day operations in StatoilHydro, and also appoints the corporate executive committee (CEC). Each of the CEC members heads separate business areas or staff functions.

The president and CEO has overall responsibility for day-to-day operations in StatoilHydro. The president and CEO is responsible for developing StatoilHydro's business strategy and presenting it to the board of directors for decision, for development and execution of the business strategy, and for nurturing a performance-driven, value-based culture.

The president and CEO appoints the corporate executive committee (CEC). Members of the CEC have a collective duty to safeguard and promote the corporate interests of StatoilHydro and to provide the president and CEO with the best possible basis for setting the company's direction, making decisions and ensuring execution and follow-up of business activities. In addition, each of the CEC members heads separate business areas or staff functions.

Members of StatoilHydro's corporate executive committee

Helge Lund. Chief executive officer

Helge Lund
Born: 1962
Position: CEO of Statoil from August 2004, CEO of StatoilHydro since 1 October 2007
External offices: None
Number of shares in StatoilHydro ASA pr. 31 December 2008: 13,857
Loans from StatoilHydro: None
Experience: Came to Statoil from the position of CEO in Aker Kværner ASA. Held central managerial positions in the Aker RGI system from1999. Has been political adviser to the Conservative Party of Norway's parliamentary group, a consultant with McKinsey & Co and Deputy Managing Director of Nycomed Pharma AS
Education: MA in business economics (siviløkonom) from the Norwegian School of Economics and Business Administration (NHH) in Bergen and Master of Business Administration (MBA) from INSEAD in France
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly
Other matters: Helge Lund is a Norwegian citizen, and he lives in Norway

Eldar Sætre. Chief financial officer

Eldar Sætre
Born: 1956
Position: CFO of Statoil from October 2003. CFO of StatoilHydro since 1 October 2007.
External offices: Member of the board of directors of Strømberg Gruppen AS.
Number of shares in StatoilHydro ASA pr. 31 December 2008: 6,057
Loans from StatoilHydro: None
Experience: He worked for Statoil from 1980 and held several management positions in the group in the fields of accounting and finance.
Education: MA in business economics (siviløkonom) from the Norwegian School of Economics and Business Administration in Bergen.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Eldar Sætre is a Norwegian citizen, and he lives in Norway.

Øystein Michelsen. Executive vice president, Exploration & Production Norway

Øystein Michelsen
Born: 1956
Position: Executive vice president in StatoilHydro since 10 November 2008
External offices: Board member of Unifob (university research company in Bergen) and OLF (the Norwegian Oil Industry Association)
Number of shares in StatoilHydro ASA pr. 31 December 2008: 2,040
Loans from StatoilHydro: None
Experience: Recruited to Hydro's research centre in Porsgrunn in 1981, he was attached to Hydro Oil and Energy division from 1985, and was head of the operations unit for Hydro's oil activities from 2004. He has been senior vice president for StatoilHydro's Operations North cluster since 1 October 2007.
Education: MA in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Øystein Michelsen is a Norwegian citizen, and he lives in Norway.

Peter Mellbye. Executive vice president, International Exploration & Production

Peter Mellbye
Born: 1949
Position: Executive vice president in Statoil from 1992. Executive vice president in StatoilHydro since 1 October 2007.
External offices: Member of the board of the Energy Policy Foundation of Norway (EPF)
Number of shares in StatoilHydro ASA pr. 31 December 2008: 7,906
Loans from StatoilHydro: None
Experience: Worked for the Ministry of Trade and the Norwegian Export Council before joining Statoil in 1982. Held several central management positions in Statoil. Executive vice president of Natural Gas from 1992 to 2004.
Education: Cand. polit. degree from the University of Oslo.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly
Other matters: Peter Mellbye is a Norwegian citizen, and he lives in Norway

Rune Bjørnson. Executive vice president, Natural Gas

Rune Bjørnson
Born: 1959
Position: Executive vice president in Statoil from 2004. Executive vice president in StatoilHydro since 1 October 2007.
External offices: None.
Number of shares in StatoilHydro ASA pr. 31 December 2008: 4,351.
Loans from StatoilHydro: None.
Experience: He worked for Statoil from 1985, holding various management positions in the Natural Gas business area. He was vice president in Statoil UK from 2001 to 2003.
Education: Cand. polit. degree from the University of Bergen.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Rune Bjørnson is a Norwegian citizen, and he lives in Norway.

Jon Arnt Jacobsen. Executive vice president, Manufacturing & Marketing

Jon Arnt Jacobsen
Born: 1957
Position: Executive vice president in Statoil from 2004. Executive vice president in StatoilHydro since 1 October 2007.
External offices: None.
Number of shares in StatoilHydro ASA pr. 31 December 2008: 7,164
Loans from StatoilHydro: None.
Experience: Worked for Den norske Bank (DnB) for 13 years where he held positions including General Manager and head of DnB's Singapore branch. Group Finance Director of Statoil from 1998 to 2004.
Education: MA in business economics (siviløkonom) from the Norwegian School of Management (BI) in Oslo and Master of Business Administration (MBA) from the University of Wisconsin.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Jon Arnt Jacobsen is a Norwegian citizen, and he lives in Norway.

Gunnar Myrebøe. Executive vice president, Projects

Gunnar Myrebøe
Born: 1949
Position: Executive vice president in StatoilHydro since 10 November 2008.
External offices: None.
Number of shares in StatoilHydro ASApr. 31 December 2008: 2,726.
Loans from StatoilHydro: None.
Experience: Worked for Phillips Petroleum before joining Statoil in 1981. Among other things, he was in charge of project development for the Sleipner condensate project, was responsible for gas technology in the Natural Gas business area, was project director for Norfra (Franpipe) and was head of Statoil research and technology.
From 2003 to 2007, Mr Myrebøe led the development of the offshore part of Snøhvit and, since the merger between Statoil and Hydro, he has been responsible for offshore modifications in the Projects business area.
Education: Graduated with a Master of Science degree (sivilingeniør) from the Norwegian University of Science and Technology (NTNU) in 1973.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Gunnar Myrebøe is a Norwegian citizen, and he lives in Norway.

Margareth Øvrum. Executive vice president, Technology & New Energy

Margareth Øvrum
Born: 1958
Position: Executive vice president in Statoil from September 2004. Executive vice president in StatoilHydro since 1 October 2007.
External offices: Board member of Elkem Atlas Copco AB and the Research Council of Norway
Number of shares in StatoilHydro ASA pr. 31 December 2008: 7,977
Loans from StatoilHydro: None
Experience: She worked for Statoil from 1982 and held central management positions in the company, including the position of executive vice president for health, safety and the environment and executive vice president for Technology & Projects. She was the company's first female platform manager, on the Gullfaks field. She was vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf.
Education: MA in engineering (sivilingeniør) from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Margareth Øvrum is a Norwegian citizen, and she lives in Norway.

Helga Nes. Executive vice president, Corporate Staffs & Services

Helga Nes
Born: 1956
Position: Executive vice president in StatoilHydro since 10 November 2008.
External offices: None.
Number of shares in StatoilHydro ASA pr. 31 December 2008: 1,397
Loans from StatoilHydro: None
Experience: Ms Nes worked for Hydro from 1984, as a process engineer, quality manager and head of staff, among other positions. Ms Nes was responsible for HSE and HR in exploration and development in Hydro's Oil and Energy division from 2002 to 2004, and IT director from 2004 to 2007.
From 2007, Ms Nes was in charge of HSE and HR in the Projects business area in StatoilHydro.
Education: Cand. real degree in organic chemistry from the Norwegian University of Science and Technology (NTNU) and a Master of Business Administration from the Norwegian BI Norwegian School of Management.
Family relations: No family relations to other members of the Corporate Executive Committee, members of the Board or the Corporate Assembly.
Other matters: Helga Nes is a Norwegian citizen, and she lives in Norway.

7.7 Nomination committee

In accordance with StatoilHydro's articles of association the nomination committee (referred to as the election committee in the articles of association) consists of four members who are shareholders, or representatives of shareholders.

The committee is independent of both the board and the company's management.

The duties of the nomination committee are:
- to present recommendations to the AGM for the election of shareholder-elected members and deputy members of the Corporate Assembly
- 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 and the corporate assembly.

A form for shareholders' nomination of candidates are made available in connection with nomination to the board of directors.

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

The members of the nomination committee are:

- Olaug Svarva (chair), managing director, Folketrygdfondet
- Gro Bækken, secretary general, Save the Children Norway
- Tom Rathke, managing director, Vital Forsikring and Executive Vice President, DnB NOR
- Bjørn Ståle Haavik, acting secretary general, Ministry of Petroleum and Energy

The nomination committee held 8 meetings in 2008.

The rules of procedure for the nomination committee are accessible at http://www.statoilhydro.com/en/AboutStatoilHydro/CorporateGovernance/GoverningBodies/ElectionCommittee/Pages/default.aspx.

7.8 Independent auditor

This section provides details about the independent auditor, and policies, procedures and remuneration relating to the auditor.

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

Pursuant to the rules of procedure, the board's audit committee is responsible for ensuring that the company is subject to an independent and effective external and internal audit.

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 board's 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 of the authorities in Norway and in the countries where StatoilHydro is listed on the stock exchange. 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 board's 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 external auditor without the company's management being present.

Audit Committee Pre-approval Policies and Procedures
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 in a regular audit committee meeting. The Chairman of the audit committee has been given the authority to pre-approve services according to policies established by the audit committee specifying in detail types of services qualifying, 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 Chairman of the audit committee if an urgent reply is deemed necessary.

Remuneration to independent auditor in 2008
Ernst & Young AS is the company's independent registered public accounting firm. The table below itemises the expensed remuneration to the external auditor in 2008 (and 2007 and 2006, respectively):

(in NOK million, excluding VAT)	Audit fee	Audit related and Other service fees *	Total
2008			
Ernst & Young - Norway	35.0	5.0	40.0
Ernst & Young - outside Norway	25.3	3.9	29.2
Total	60.3	8.9	69.2
2007			
Ernst & Young - Norway	20.7	7.4	28.1
Ernst & Young - outside Norway	24.1	1.1	25.2
Total	44.8	8.5	53.3
2006			
Ernst & Young - Norway	15.9	4.2	20.1
Ernst & Young - outside Norway	19.9	2.4	22.3
Total	35.8	6.6	42.4

* Included in the amount for 2008 is NOK 0.4 million related to miscellaneous services at several locations.

All fees included in the table were approved by the audit committee.

Audit Services are defined as the standard audit work that needs to be performed each year in order to issue an opinion on the consolidated financial statements of StatoilHydro, and to issue reports on the IFRSs statutory financial statements. It also includes other audit services which are those services that only the independent auditor reasonably can provide, such as auditing of non-recurring transactions and application of new accounting policies, audits of significant and newly implemented system controls and limited reviews of quarterly financial results.

Audit Related Services include those other assurance and related services provided by auditors, but not restricted to those that can only reasonably be provided by the external auditor signing the audit report, that are reasonably related to the performance of the audit or review of the company's financial statements such as acquisition due diligence, audits of pension and benefit plans, consultations concerning financial accounting and reporting standards.

In addition to the figures in the table above, we paid audit fee and other fees to Deloitte amounting to NOK 39.4 and NOK 5.6 million for 2007 and 2006, while audit fees to Ernst & Young relating to StatoilHydro-operated licences amounted to NOK 8.5, NOK 6.1 and NOK 4.0 million for the years 2008, 2007 and 2006, respectively. These fees are in addition to the figures in the table above.

The increases in audit fees and audit related and other fees from 2006 to 2007 and from 2007 to 2008 are mainly due to the increase in activity in connection with the merger with Hydro Petroleum.

7.9 Compensation to the governing bodies

This section details compensation paid to the board of directors, corporate executive committee and corporate assembly.

In 2008, aggregate compensation totalling NOK 828,660 was paid to the members of the corporate assembly, NOK 4,572,000 to the members of the board of directors, NOK 43,233,000 to the members of the corporate executive committee.

Detail information about the individual compensation of members of the board of directors and the members of the corporate executive committee in 2008 is given in the tables below.

Members of the board (In thousand NOK)	Board remuneration	Audit committee	Compensation committee	Total remuneration
Rennemo Svein *	440	0	14	454
Arnstad Marit **	417	100	0	517
Skaugen Grace R.	294	0	50	344
Grieg Elisabeth	294	0	28	322
Svaan Morten	294	100	0	394
Bjørndalen Kjell	294	0	35	329
Nielsen Kurt Anker	294	150	0	444
Fritsvold Ragnar Per	294	0	0	294
Franklin Roy	492	100	0	592
Nilsen Geir	294	0	0	294
Clausen Claus	294	0	0	294
Bakkerud Lill-Heidi	294	0	0	294
Total	3,995	450	127	4,572

* Chair of the Board from 1 April 2008

** Acting chair of the Board from 1 January through 31 March 2008

Members of Corporate Executive Committee	Fixed Salary 2)	LTI 3)	Bonus 4)	Benefits in kind	Taxable re-imburse-ments	Taxable salary	Benefits in kind	Re-imbur-sements	Non taxable salary	Total Remuner-ation	Pension cost 5)	Present value of pension obligation
Lund Helge (CEO)	6,847	1,890	550	369	21	9,677	479	17	496	10,173	5,317	22,289
Bjørnson Rune (Executive vice president (E.V.P), Natural Gas)	2,535	600	113	191	21	3,460	0	26	26	3,486	822	18,346
Jacobsen Jon Arnt (E.V.P, Manufacturing & Marketing)	3,038	669	131	59	15	3,912	0	44	44	3,956	1,514	15,286
Mellbye Peter (E.V.P, International Exploration & Production)	4,194	813	108	141	22	5,278	54	39	93	5,371	1,364	41,945
Sætre Eldar (CFO)	3,047	713	154	196	30	4,140	177	24	201	4,341	924	25,129
Øvrum Margareth (E.V.P, Technology & New Energy)	3,375	694	138	54	23	4,284	55	50	105	4,389	876	22,623
Nes Helga 1) (E.V.P, Staff functions & corporate services for the period 10.11.08 - 31.12.08)	412	0	0	18	6	436	21	5	26	462	369	8,306
Michelsen Øystein 1) (E.V.P, Exploration & Production Norway for the period 10.11.08 - 31.12.08)	591	0	0	26	1	618	37	19	56	674	581	14,741
Myrebø Gunnar 1) (E.V.P, Projects for the period 10.11.08 - 31.12.08)	452	0	0	2	4	458	0	7	7	465	501	13,589
Ruud Morten 1) (E.V.P, Projects for the period 01.01.08 - 06.10.08)	1,980	590	0	11	15	2,596	0	28	28	2,624	0	19,460
Torvund Tore 1) (E.V.P, Exploration & Production Norway for the period 01.01.08 - 06.10.08)	2,958	863	0	16	8	3,845	168	33	201	4,046	0	36,541
Aasheim Hilde Merete 1) (E.V.P, Staff functions & corporate services for the period 01.01.08 - 01.11.08)	2,239	131	500	153	0	3,023	217	6	223	3,246	0	1,645
Total	31,668	6,963	1,694	1,236	166	41,727	1,208	298	1 506	43,233	12,268	239,900

1) The figures presented are total direct compensation for the period when a position in the Corporate Executive Committee is held.

2) Fixed salary consists of base salary, holiday allowance and any other administrative benefits.
3) Fixed long-term incentive element.
4) Bonus received in 2008 is related to the variable long-term incentive system that was terminated in 2007. Bonuses for the period 1 October 2007 to 31 December 2008 will be paid in 2009.
5) Pension cost is calculated based on actuarial assumptions and pensionable salary at 31 December 2008 and will be recognised as pension cost in the Statement of Income in 2009. The figures presented represent benefits earned assuming that a position in the Corporate Executive Committee is held for a full year. Payroll tax is not included.

7.10 Share ownership

This section describes the number of StatoilHydro shares owned by the members of the board of directors and the executive committee.

The number of StatoilHydro shares owned by the members of the board of directors and the executive committee, and/or owned by their close associates, is shown below. Each member of the board of directors and the executive committee individually owned less than 1% of the StatoilHydro shares outstanding.

Ownership of StatoilHydro shares (including share ownership of "close associates")	As of 31 December 2008	As of 6 March 2009
Members of the Corporate Executive Committee		
Helge Lund	13,857	14,520
Eldar Sætre	6,057	6,236
Margareth Øvrum	7,977	8,195
Rune Bjørnson	4,351	4,564
Jon Arnt Jacobsen	7,164	7,482
Peter Mellbye	7,906	8,050
Øystein Michelsen	2,040	2,040
Gunnar Myrebøe	2,726	2,870
Helga Nes	1,397	1,397
Members of the Board of Directors		
Svein Rennemo	10,000	10,000
Marit Arnstad	0	0
Elisabeth Grieg	33,108	33,108
Kjell Bjørndalen	0	0
Grace Reksten Skaugen	400	400
Kurt Anker Nielsen	0	0
Roy Franklin	0	0
Lill-Heidi Bakkerud	330	330
Claus Clausen	165	165
Morten Svaan	933	954
Ragnar Fritsvold (observer)	468	468
Geir Nilsen (observer)	626	626

Each member of the corporate assembly individually owned less than 1% of StatoilHydro shares outstanding as of 31 December 2008 and as of 6 March 2009. Members of the corporate assembly in aggregate owned a total of 5,665 shares as of 31 December 2008 and a total of 5,665 shares as of 6 March 2009.

Information about share ownership by members of the Corporate Assembly is presented in Section 7.5.

Members of the board of directors, executive committee and corporate assembly do not have different voting rights from the rights of ordinary shareholders.

7.11 Controls and procedures

This section describes controls and procedures relating to our financial reporting.

Evaluation of disclosure controls and procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by Form 20-F. Based on that evaluation, the chief executive officer and chief financial officer have concluded that these disclosure controls and procedures are effective at a reasonable level of assurance.

In order to facilitate the evaluation, StatoilHydro established a disclosure committee in January 2008 to review material disclosures made by StatoilHydro for any errors, misstatements and omissions. The disclosure committee is chaired by the chief financial officer. It consists of the heads of Investor Relations, Accounting and Financial Control, Tax and General Counsel and may be supplemented by other internal and external personnel. The head of the Internal Audit is an observer at the committee's meetings.

In designing and evaluating our disclosure controls and procedures, our management, with the participation of the chief executive officer and chief financial officer, recognised that any controls and procedures, no matter how well designed and operated, can only provide reasonable assurance that the desired control objectives will be achieved, and that our management must necessarily exercise judgment in evaluating the cost-benefit aspects of possible controls and procedures. Because of the limitations inherent in all control systems, no evaluation of controls can provide absolute assurance that all control issues and any instances of fraud in the company have been detected.

The management's report on internal control over financial reporting

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

Management has assessed the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management has determined that StatoilHydro's internal control over financial reporting as of 31 December 2008 was effective.

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

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

The effectiveness of internal control over financial reporting as of 31 December 2008 has been audited by Ernst & Young AS, an independent registered public accounting firm which also audits our consolidated financial statements included in this Annual Report. Their audit report on internal control over financial reporting is included in the Consolidated Financial Statements section 8 of this report.

Changes in internal controls over financial reporting

No changes occurred in our internal control over financial reporting during the period covered by Form 20-F that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

8 Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF INCOME

(in NOK million)	Note	For the year ended 31 December 2008	2007	2006
REVENUES AND OTHER INCOME				
Revenues		**651,977**	521,665	518,960
Net income (loss) from associated companies	13	**1,283**	609	679
Other income		**2,760**	523	1,843
Total revenues and other income	5	**656,020**	522,797	521,482
OPERATING EXPENSES				
Purchases [net of inventory variation]		**(329,182)**	(260,396)	(249,593)
Operating expenses		**(59,349)**	(60,318)	(44,801)
Selling, general and administrative expenses		**(10,964)**	(14,174)	(10,824)
Depreciation, amortisation and impairment losses	11	**(42,996)**	(39,372)	(39,450)
Exploration expenses		**(14,697)**	(11,333)	(10,650)
Total operating expenses		**(457,188)**	(385,593)	(355,318)
Net operating income	5	**198,832**	137,204	166,164
FINANCIAL ITEMS				
Net foreign exchange gains (losses)		**(32,563)**	10,043	4,457
Interest income and other financial items		**12,207**	2,305	3,675
Interest and other finance expenses		**1,991**	(2,741)	(3,060)
Net financial items	8	**(18,365)**	9,607	5,072
Income before tax		**180,467**	146,811	171,236
Income tax	9	**(137,197)**	(102,170)	(119,389)
Net income		**43,270**	44,641	51,847
Attributable to:				
Equity holders of the parent company		**43,265**	44,096	51,117
Minority interest		**5**	545	730
		43,270	44,641	51,847
Earnings per share for income attributable to equity holders of the company - basic and diluted	10	**13.58**	13.80	15.82

CONSOLIDATED BALANCE SHEETS

(in NOK million)		At 31 December 2008	2007
ASSETS			
Non-current assets			
Property, plant and equipment	11	**329,841**	278,352
Intangible assets	12	**66,036**	44,850
Investments in associated companies	13	**12,640**	8,421
Deferred tax assets	9	**1,302**	793
Pension assets	21	**30**	1,622
Financial investments	14	**16,465**	15,266
Derivative financial instruments	28	**2,383**	609
Financial receivables	14	**4,914**	3,515
Total non-current assets		**433,611**	353,428
Current assets			
Inventories	15	**15,151**	17,696
Trade and other receivables	16	**69,931**	69,378
Current tax receivable	3	**3,840**	0
Derivative financial instruments	28	**27,505**	21,093
Financial investments	17	**9,747**	3,359
Cash and cash equivalents	18	**18,638**	18,264
Total current assets		**144,812**	129,790
TOTAL ASSETS		**578,423**	483,218

CONSOLIDATED BALANCE SHEETS

(in NOK million)		At 31 December 2008	2007
EQUITY AND LIABILITIES			
Equity			
Share capital		**7,972**	7,972
Treasury shares		**(9)**	(6)
Additional paid-in capital		**41,450**	41,370
Additional paid-in capital related to treasury shares		**(586)**	(359)
Retained earnings		**147,998**	140,909
Other reserves		**17,254**	(12,611)
StatoilHydro shareholders' equity		**214,079**	177,275
Minority interest		**1,976**	1,792
Total equity	19	**216,055**	179,067
Non-current liabilities			
Financial liabilities	20	**54,606**	44,374
Deferred tax liabilities	9	**68,144**	67,477
Pension liabilities	21	**25,538**	19,092
Asset retirement obligations, other provisions and other liabilities	22	**54,359**	43,845
Total non-current liabilities		**202,647**	174,788
Current liabilities			
Trade and other payables	23	**61,200**	64,624
Current tax payable	9	**57,074**	50,941
Financial liabilities	20	**20,695**	6,166
Derivative financial instruments	28	**20,752**	7,632
Total current liabilities		**159,721**	129,363
Total liabilities		**362,368**	304,151
TOTAL EQUITY AND LIABILITIES		**578,423**	483,218

CONSOLIDATED STATEMENTS OF RECOGNISED INCOME AND EXPENSE (SORIE)

	For the year ended 31 December		
(in NOK million)	2008	2007	2006
Foreign currency translation differences	**30,880**	(9,858)	(3,817)
Actuarial gains (losses) on employee retirement benefit plans	**(7,945)**	74	(3,032)
Change in fair value of available for sale financial assets	**(1,362)**	1,039	(524)
Change in fair value of available for sale financial assets transferred to the Consolidated statements of income	**0**	(113)	0
Income tax on income and expense recognised directly in equity	**(802)**	(175)	2,321
Income and expense recognised directly in equity	**20,771**	(9,033)	(5,052)
Net income for the period	**43,270**	44,641	51,847
Total recognised income and expense for the period	**64,041**	35,608	46,795
Attributable to:			
Equity holders of the parent company	**64,036**	35,063	46,065
Minority interest	**5**	545	730
	64,041	35,608	46,795

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2008	2007	2006
OPERATING ACTIVITIES			
Income before tax	**180,467**	146,811	171,236
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortisation and impairment	**42,996**	39,372	39,450
Exploration expenditures written off	**3,872**	1,660	1,447
(Gains) losses on foreign currency transactions and balances	**15,243**	(559)	(1,197)
(Gains) losses on sales of assets and other items	**(2,704)**	(188)	(2,371)
Termination benefits	**0**	8,633	0
Changes in working capital (other than cash and cash equivalents):			
• (Increase) decrease in inventories	**2,470**	(2,434)	(2,850)
• (Increase) decrease in trade and other receivables	**(1,129)**	(6,493)	1,060
• (Increase) decrease in net current financial derivative instruments	**6,708**	1,307	(12,450)
• (Increase) decrease in current financial investments	**(6,388)**	(2,327)	5,810
• Increase (decrease) in trade and other payables	**(5,466)**	10,447	(3,496)
Taxes paid	**(139,604)**	(102,422)	(108,174)
(Increase) decrease in non-current items related to operating activities	**6,068**	119	128
Cash flows provided by operating activities	**102,533**	93,926	88,593
INVESTING ACTIVITIES			
Additions through business combinations	**(13,120)**	0	0
Additions to property, plant and equipment	**(58,529)**	(63,785)	(45,177)
Exploration expenditures capitalised	**(6,821)**	(4,569)	(4,188)
Additions to other intangibles	**(10,828)**	(7,186)	(10,507)
Change in long-term loans granted and other long-term items	**(1,910)**	(652)	(726)
Proceeds from sale of assets	**5,371**	1,080	3,423
Cash flows used in investing activities	**(85,837)**	(75,112)	(57,175)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2008	2007	2006
FINANCING ACTIVITIES			
New long-term borrowings	**2,596**	1,723	97
Repayment of long-term borrowings	**(2,864)**	(2,876)	(2,270)
Distribution (to)/from minority shareholders	**179**	(327)	(741)
Dividend paid *	**(27,082)**	(25,695)	(17,756)
Treasury shares purchased	**(308)**	(217)	(1,012)
Norsk Hydro ASA merger balance	**0**	18,687	(10,025)
Net short-term borrowings, bank overdrafts and other **	**10,450**	797	329
Cash flows used in financing activities	**(17,029)**	(7,908)	(31,378)
Net increase (decrease) in cash and cash equivalents	**(333)**	10,906	40
Effect of exchange rate changes on cash and cash equivalents	**707**	(160)	42
Cash and cash equivalents at the beginning of the period	**18,264**	7,518	7,436
Cash and cash equivalents at the end of the period	**18,638**	18,264	7,518
Interest paid	**2,771**	3,709	3,611
Interest received	**4,544**	2,256	2,296

* 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, StatoilHydro has paid the state NOK 2.4 billion in 2007.

8.1 Notes to the Consolidated Financial Statements

8.1.1 Organisation

StatoilHydro ASA, formerly Den Norske Stats Oljeselskap AS, was founded in 1972 and is incorporated and domiciled in Norway. The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

StatoilHydro's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products.

Effective 1 October 2007, Statoil ASA merged with the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). Statoil ASA's name changed to StatoilHydro ASA as of that date.

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

8.1.2 Significant accounting policies

Statement of compliance

The Consolidated financial statements of StatoilHydro ASA and its subsidiaries (the "group") 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 and in preparing an opening IFRS balance sheet at 1 January 2006 (subject to certain exemptions allowed by IFRS 1) for the purpose of the transition to IFRS. For details of the transition to IFRS see StatoilHydro's Consolidated Financial Statements for 2007.

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.

Early adoption of standards and interpretations

The group has elected to adopt the following standards, amendments and interpretations in advance of their effective dates: IAS 23 (Revised) *Borrowing Costs* (effective for accounting periods beginning on or after 1 January 2009) and IFRS 8 *Operating Segments* (effective for accounting periods beginning on or after 1 January 2009). The standards have been implemented retrospectively for the periods presented as if the policies have always been applied.

Standards and interpretations in issue not yet adopted

At the date of these financial statements, other than the standards and interpretations adopted by the group in advance of their effective dates as described above, the following standards and interpretations were in issue but not yet effective:

The amendments to IAS 1 *Presentation of Financial Statements* issued in September 2007, which will be effective for annual periods beginning on or after 1 January 2009. This revised IAS introduces certain changes to the statement of recognised income and expense. The group will present a statement of comprehensive income and a statement of changes in equity where currently a statement of income and a statement of recognised income and expense are included. Actuarial gains and losses related to pensions will be presented in other comprehensive income, whereas these are currently presented in the statement of recognised income and expense. There will be no effect on the group's reported net income or equity.

The revised version of IFRS 3 *Business Combinations,* issued in January 2008, will be applicable to business combinations occurring in annual periods beginning on or after 1 July 2009. There will be no effect on the group's reported net income or equity on adoption.

The amended version of IAS 27 *Consolidated and Separate Financial Statements* issued in January 2008 is effective for periods beginning on or after 1 July 2009. There will be no effect on the group's reported net income or equity on adoption.

The amendments to IAS 32 *Financial Instruments: Presentation* and IAS 1 *Presentation of Financial Statements* issued in February 2008 are effective for annual periods beginning on or after 1 January 2009 and will not significantly impact the group's assets, liabilities, or note disclosures.

The Improvements to IFRS 2008 issued in May 2008 are effective for accounting periods beginning on or after 1 January 2009 and include amendments to a number of accounting standards. None of the amendments will significantly impact the group's net profit or equity or classifications in the Balance sheet or Statement of income.

The amended version of IFRS 1 *First-time adoption of IFRS* and IAS 27 *Consolidated and Separate Financial Statements* issued in May 2008 is effective for periods beginning on or after 1 January 2009 and will not significantly impact the group's assets, liabilities, or note disclosures.

The amendments to IAS 39 *Financial Instruments Recognition and Measurements* issued in July 2008 will have effect from1 July 2009 and will be applied by the group when relevant. There will be no impact on the group's assets, liabilities or net income for periods presented.

IFRIC 18 *Transfers of Assets from Customers*, issued in January 2009, is effective from 1 July 2009. The group has not yet completed its evaluation of the effect of the future adoption of IFRIC 18, but the preliminary assessement indicates that there will be no significant impact on the group's assets, liabilities or net income.

The amendments to IFRS 7 *Financial Instruments: Disclosures,* issued in March 2009, enhance disclosure requirements about fair value measurements and liquidity risk and is effective for annual periods beginning on or after 1 January 2009. The amendments, which do not require comparative disclosures in the first year of application, is currently being evaluated by the group and will be reflected in the group's note disclosure for the year ended 2009.

The amendment to IFRS 2 *Share-based payment* issued in January 2008, (effective 1 January 2009), IFRIC 15 Agreements for the Construction of Real Estate (effective 1 January 2009) and IFRIC 17 Distribution of Non-cash Assets to Owners (effective 1 July 2009) are currently not relevant to the group.

Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of StatoilHydro ASA and its subsidiaries. Subsidiaries are entities controlled by the company. Control exists when the group 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 the group 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 intragroup transactions, have been eliminated in full. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not directly or indirectly held by the parent company and is presented separately within equity in the consolidated balance sheet.

Jointly controlled assets, associates and joint venture entities

Interests in jointly controlled assets are recognised by including the group'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 the group 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.

StatoilHydro as operator of jointly controlled assets

Indirect operating expences such as personnel expenses are accumulated in cost pools. These costs are allocated to business areas and StatoilHydro operated jointly controlled assets (licenses) on an hours incurred basis. Costs allocated to the other partners' share of operated jointly controlled assets reduce the costs in the group statement of income. Only StatoilHydro's share of the statement of income and balance sheet items related to StatoilHydro operated jointly controlled assets are reflected in the Consolidated 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 statement of income and balance sheet 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 directly as a separate component of equity in the Statement of recognised income and expense.

Business combinations and goodwill

In order for a business combination to exist, 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), which generally consists of inputs, processes and outputs. This requires judgment to be applied on a case by case basis as to whether the acquisition meets the definition of a business combination. Acquired exploration and evaluation licences for which no decision has been made to develop are treated as asset purchases based on provisions in IFRS 6. Acquisitions of licences for which a development decision has been made are assessed under the criteria described above to establish whether the transaction represents a business combination or an asset purchase.

Business combinations, except for transactions between entities under common control, are 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 passes 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 the group have an interest with other companies are recognised on the basis of volumes lifted and sold to customers during the period (the sales method). Where the group has lifted and sold more than the ownership interest, an accrual is recorded for the cost of the overlift. Where the group 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 statement of income. Activities related to trading and commodity-based derivative instruments are reported on a net basis, with the margin included in Revenue.

Transactions with the Norwegian State

The group markets and sells the Norwegian State's share of oil and gas production from the Norwegian Continental Self (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. The group 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 the group's financial statements. Such refundable expenditures relate to activities incurred to secure market access, transportation, processing capacity and investments made to maximise profitability from the sale of natural gas.

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

The group 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, see note 6 Remuneration, and recorded as an equity transaction (included in additional paid-in capital).

Research and development

The group undertakes research and development both on a funded basis for licence holders, and unfunded projects at its own risk. The group'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 measure reliably 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 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 is provided using the balance sheet liability method. 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. However, the existence of unused tax losses is strong evidence that future taxable profits may not be available. In order to recognise a deferred tax asset 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 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

The group 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 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 group has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are also reflected in the financial statements as and when the exploration and development work progresses, in line with the group's policy. 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 amount 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, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the license, or a development decision is planned in the near future. Impairment of unsuccessful wells is reversed, as applicable, to the extent that conditions for impairment are no longer present.

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 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 any 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 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, 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 group 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 group assumes substantially all the risks and rewards of the ownership are recorded as finance leases within Property, plant and equipment and Financial liabilities. 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.

Assets recorded under finance leases are stated 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 any impairment losses. When an asset leased by a jointly controlled asset in which the group participates qualifies as a finance lease, the group 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 group 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 the group.

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. These assets are subject to impairment testing when facts and circumstances suggest that the carrying amount of the asset may exceed its recoverable amount, and are reclassified to property, plant and equipment when the decision to develop a particular area is made. Other intangible assets are amortised on a straight-line basis over their expected useful lives. The expected useful lives of the assets are reviewed on an annual basis and changes in useful lives are accounted for prospectively.

Financial assets
Financial assets are initially recognised at fair value when the group becomes a party to the contractual provisions of the asset. For additional information on fair value methods, refer to the "Measurement of fair value" section below. The subsequent measurement of the financial assets depends on what category they are classified into at inception.

At initial recognition the group classifies its financial assets into the following three main categories; financial investments at fair value through profit or loss; loans and receivables; and as available-for-sale (AFS) financial assets. The first main category; financial investments at fair value through profit or loss, consist further of two sub-categories; financial assets that as held for trading and financial assets that on initially recognition is designated as fair value through profit and loss. The latter is further also 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 Consolidated 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 an allowance made for doubtful receivables. Provision is made when there is objective evidence that the group will be unable to recover balances in full.

Non-listed equity securities are classified as AFS. AFS financial assets are carried on the balance sheet at fair value, with the change in fair value recognised directly into equity 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 equity is recognised in the statement of income.

A significant part of the group's commercial papers, bonds and listed equity securities are managed together as an investment portfolio by the group's captive insurance company and are held to comply with specific regulations for capital retention. The investment portfolio is managed and evaluated on a fair value basis in accordance with an investment strategy and is accounted for using the fair value option with changes in fair value recognised through profit or loss.

Financial assets are presented as current if the asset is expected to be recovered within 12 months after the balance sheet date, whereas assets expected to be recovered more than 12 months after the balance sheet date are classified as non-current, with the exception for derivative financial instruments classified in the held for trading category.

Financial assets are derecognised when the contractual rights to the cash flows expire or substantially all risk and rewards related to the ownership of the financial asset is transferred in a manner that meet the derecognising criterias.

Non-current financial investments comprise listed equity securities, non-listed equity securities, commercial papers and bonds.

Current financial investments comprise commercial papers and money market funds. The current financial investments are at initially recognition in the category 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 value recognised in the income statement.

Non-current financial receivables comprise long term interest bearing receivables and are classified in the loan and receivables category at initial recognition.

Trade and other receivables are in the category of loans and receivables.

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash and have a maturity of three months or less from the date of acquisition.

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
Intangible assets and property, plant and equipment
The group 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 the level that there are 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 is required in the carrying amount of a potentially impaired asset, the asset's carrying amount is compared to the recoverable amount. Generally the recoverable amount of an asset is the group'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 in 2008, 2007 and 2006 using a real post-tax discount rate of 6.5%. The discount rate is calculated based on the group's post-tax weighted average cost of capital (WACC). The group considers that post-tax calculations are more appropriate for impairment calculation purposes compared to pre-tax calculations, although IAS 36 suggest the use of pre-tax.

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.

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 against goodwill and then pro-rata to the other assets of that unit. Impairments of goodwill are not reversed in future periods.

Financial assets
The group 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 trough 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 income statement. Any subsequent reversal of an impairment loss is recognised in the income statement.

If an available-for-sale financial asset is impaired, i.e. because the decline in fair value has been assessed to be significant or prolonged, the difference between cost and fair value is transferred from equity to the income statement. When impairments of equity instruments classified as available-for-sale are reversed this is recogniced directly to equity.

Financial liabilities
Financial liabilities are initially recognised at fair value when the group becomes a party to the contractual provisions of the liability. For additional information on fair value methods, refer to the "Measurement of fair value" section below. The subsequent measurement of the financial liabilities depends on what category they are classified into at inception. The categories applicable for the group is either financial liabilities at fair value through profit or loss or financial liability measured at amortised cost using the effective interest method.

Financial liabilities are presented as current if the liability is due to be settled within 12 months after the balance sheet date, whereas liabilities with the legal right to be settled more than 12 months after the balance sheet date are classified as non-current, with the exception for derivative financial instruments classified at fair value through profit or loss in in the held for trading category.

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 and interest and other finance expenses.

Non-current financial liabilities comprise interest-bearing bonds, bank loans, financial lease obligation and other debt.

Current financial liabilities comprise collateral liabilities, commercial papers, current portion of non-current financial liabilities, including financial lease obligations and other current debt.

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

Pension liabilities
The group 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 increases.

The group'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 Consolidated 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 Consolidated 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 StatoilHydro operated jointly controlled assets (licenses) on an hours incurred basis and recognised in the Consolidated 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 remeasured using current actuarial assumptions and the gain or loss is recognised in the Consolidated statement of income during the period in which the settlement or curtailment occurs.

Actuarial gains and losses are recognised in full in the Consolidated statement of recognised income and expense in the period in which they occur.

Contribution to defined contribution schemes are recognised in the Consolidated statement of income in the period in which the contribution amounts are earned by the employees.

Provisions

Provisions are recognised when the group 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.

Possible assets arising from past events that will only be confirmed by future uncertain events and are not wholly within the control of the group, are not recognised, but are disclosed when an inflow of economic benefits is probable.

Onerous Contracts

The group 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 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 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 the group 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 oil and natural gas production or transportation facilities, 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 Other provisions. 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 an expected license period have indefinite lives and therefore there is no measurable asset retirement obligation to be 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.

Derivative financial instruments and hedge accounting

The group 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. 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 for derivative financial instruments classified in the held for trading category. For the group it is therefore only derivative financial instruments designated as an effective hedging instrument that is classified as non-current in line with the classification of the hedging object.

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 the group'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 that are accounted for as executory contracts.

Embedded derivatives
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 the group becomes a party to them, including at the date of a business combination. These 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.

Hedge accounting
For those derivatives designated as hedging instruments and where hedge accounting is to be applied, the hedging relationship is documented at its inception. This documentation identifies the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how effectiveness will be assessed throughout its duration. Such hedges are expected at inception to be highly effective.

Fair value hedges
Fair value hedges are used by the group when we are hedging the exposure to changes in the fair value of a recognised asset or liability. For fair value hedges, the carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged; the derivative is re-measured at fair value and gains and losses from both the hedging instrument and the hedged item are recognised in the same line in the income statement. For hedged items carried at amortised cost, the adjustment is amortised through the income statement such that it is fully amortised by maturity. The adjustment is included in the amortisation calculation at the time when the hedged item no longer is adjusted for changes in fair value, either because the hedging instruments have expired or the hedge no longer meets the requirements for hedge accounting. The group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer meets the criteria for hedge accounting or the group revokes the designation.

Measurement of fair values
A financial instrument is regarded as quoted in an active market if the prices quoted are readily and regularly available, for example through an exchange, and the prices quoted by the exchange represent actual and regularly occurring market transactions. This will typically include, but is not limited to, commodity based futures, exchange traded option contracts and equity instruments with quoted market prices obtained from the relevant exchanges or clearing houses. The fair values of quoted financial assets and 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 when valuing contracts not traded in an active market. This is either reflected in the discount rate used, or through direct adjustments to the calculated cash flows. Consequently, where the group records elements of long-term physical delivery commodity contracts at fair value, such fair value estimates are to the extent possible 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. Likewise, the fair value of interest and currency swaps is 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 the group has made in the process of applying the accounting policies and that have the most significant effect on the amounts recognised in the financial statements:

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
As described under Transactions with the Norwegian State above, the group markets and sells the Norwegian State's share of oil and gas production from the NCS. The group includes the costs of purchase and proceeds from the sale of the SDFI oil production in its Cost of goods sold and Revenue, respectively. In making the judgement the group considered the detailed criteria for the recognition of revenue from the sale of goods set out in IAS 18 Revenue, and assessed in particular by analogy whether the risk and reward of the ownership of the goods had been transferred from the SDFI to the group.

As also described above, the group 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 the group's financial statements. In making the judgment the group 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 the group.

Method of accounting applied for the Hydro Petroleum merger
The merger between former Statoil ASA and Hydro Petroleum has been accounted for using the carrying amounts of the assets and liabilities. When making this judgement the group 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. StatoilHydro concluded that such a reorganisation would be best presented using the carrying amounts of assets and liabilities, and restating all 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.

The group is exposed to a number of underlying economic factors, such as liquids prices, natural gas prices, refining margins, foreign exchange rates, as well as financial instruments with fair value derived from changes in these factors, which affect the overall results. In addition, the results of the group are influenced by the level of production, which in the short term may be influenced by for instance maintenance. 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 in accordance with industry standards and governed by criteria established by regulations of the SEC. 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. An independent third party has evaluated StatoilHydro's proved reserves estimates, and the results of such evaluation do not differ materially from management estimates. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions. 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 in accordance with 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 adverse effect on operating income as a result of increased impairment charges.

Exploration and leasehold acquisition costs. The group accounting policy is to capitalise the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. The group also capitalises leasehold acquisition costs and signature bonuses paid to obtain access to undeveloped oil and gas acreage. Judgments on 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. The group has significant investments in property, plant and equipment and intangibles. 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 the 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. Exploratory wells that have found reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified, may remain capitalised for more than one year. The main conditions are that either firm plans exist for future drilling in the license or a development decision is planned in the near future.

Estimating the recoverable amount involves complexity in estimating relevant future cash flows, based on future assumptions, 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, currency exchange rates and future output, discount rates and political and country risk among others, in order to establish relevant future cash flows. Long-term assumptions for major 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 consolidated balance sheet, and indirectly, the period's net pension expense in the consolidated statement of income, management make a number of critical assumptions affecting these estimates. Most notably, assumptions made on 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 material impact on the amounts presented. Significant changes in these assumptions between periods can have a material effect on the accounts.

Asset retirement obligations. The group 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 income statement.

Income tax. The group annually incurs significant amounts of income taxes payable to various jurisdictions around the world, and also recognises significant changes to deferred tax assets and deferred tax liabilities, all of which are based on management's interpretations of applicable laws, regulations and relevant court decisions. The quality of these estimates is highly dependent upon management's ability to properly apply at times very complex sets of rules, to recognise changes in applicable rules and, in the case of deferred tax assets, management's ability to project future earnings from activities that may apply loss carry forward positions against future income taxes.

8.1.3 Business combinations

In December 2008 StatoilHydro acquired the remaining 50% interest in the Peregrino heavy-oil field offshore Brazil, after closing the deal to acquire Anadarko's 50% stake on 10 December 2008. StatoilHydro paid a cash consideration of USD 1.8 billion, including expenditures incurred in the period 1 January to 11 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, StatoilHydro 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 value or final payment of the contingent consideration element will be recorded as an adjustment to the book value of the assets acquired. See table below for further details on the purchase price allocation.

(in NOK million)	Carrying amount	Fair value
Property, plant and equipment	2,518	12,435
Intangible assets	0	1,543
Current assets	70	70
Total assets acquired	2,588	14,048
Current Liabilities	(316)	(323)
Net assets acquired	2,272	13,725

Intangible assets consists of licenses in the exploration and evaluation phase. No part of the purchase price was allocated to goodwill.

StatoilHydro's original share of 50% in South Atlantic Holding BV has previously been accounted for as an associated company using the equity method. As a result of the business combination, the entity is now consolidated and (in addition to the amounts shown in the table above) the book value of net assets previously accounted for using the equity method has been accounted for as additions through business combinations in note 11 Property, plant and equipment. The transaction has been recorded in the segment International Exploration and Production.

The acquired business has not generated any revenues and has not incurred significant operating expenses in the period from 1 January 2008 to the acquisition date, or in the period after the acquisition date, as the operations have mainly been related to development and exploration activities, for which the expenditures have been capitalised as intangible assets (exploration) and property, plant and equipment (development).

8.1.4 Significant acquisitions and dispositions

In November 2008 StatoilHydro 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. StatoilHydro paid a cash consideration of USD 1.3 billion and will pay an additional USD 2.1 billion in the form of future 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, on the basis of provisions in IFRS 6, be recorded in the financial statements at the time the expenditures for the wells are incurred. The transaction has been recorded in the segment International Exploration and Production, and was not considered a business combination.

In February 2008 StatoilHydro'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 PDVSA. 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 has been recognised in the Consolidated statements of income in 2008 by NOK 1.1 billion net of tax. The transaction has been 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 on a line-by-line basis.

In the second quarter of 2007 StatoilHydro acquired all shares of North American Oil Sands Corporation (NAOSC) for a consideration of CAD 2.2 billion, equivalent to USD 2.0 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, north-east of Edmonton. The transaction has been recorded in the segment International Exploration and Production, and was not considered a business combination.

In the first quarter of 2007 StatoilHydro 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 StatoilHydro acquired an additional 15% working interest in the Big Foot discovery and has now a 27.5% working interest, including the additions from the transaction mentioned below. The transaction has been recorded in the segment International Exploration and Production. The transaction was not considered a business combination.

In the fourth quarter of 2006 StatoilHydro acquired working interests in two US Gulf of Mexico deepwater discoveries and one exploration prospect at a cost of USD 0.7 billion. The assets are located in the Greater Tahiti and Walker Ridge areas. StatoilHydro acquired a 17.5% working interest in the Caesar discovery (the Caesar discovery has subsequently been unitised with the Tonga discovery) and a 12.5% working interest in the Big Foot discovery. The transaction has been recorded in the segment International Exploration and Production. The transaction was not considered a business combination.

8.1.5 Segments

Business segments

StatoilHydro manages its operations in four business 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 segments follows the accounting principles used in the financial statement as described in note 2 Significant accounting policies.

Segment data for the years ended 31 December, 2008, 2007 and 2006 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 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 (loss) 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 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

* Excluding investments in associated companies.
** Deferred tax assets, post employment benefit assets and financial instruments are not allocated to segments.
*** Excluding additions due to changes in estimated cost of abandonment and removal.

(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 (loss) 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 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.

** Excluding investments in associated companies.

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

**** Excluding additions due to changes in estimated cost of abandonment and removal.

(in NOK million)	Exploration and Production Norway	International Exploration and Production	Natural Gas	Manufacturing and Marketing	Other	Eliminations	Total
Year ended 31 December 2006							
Revenues third party and Other income	3,576	11,987	96,040	410,689	1,778	(3,267)	520,803
Revenues inter-segment	175,544	20,608	832	899	1,986	(199,869)	0
Net income (loss) from associated companies	79	7	197	402	(6)	0	679
Total revenues and other income	179,199	32,602	97,069	411,990	3,758	(203,136)	521,482
Net operating income	135,140	3,917	21,693	7,280	(1,427)	(439)	166,164
Significant non-cash items recognised in segment profit or loss							
- Depreciation, amortisation and impairment losses	20,708	9,468	1,425	2,223	437	0	34,261
- Impairment losses	230	4,902	0	57	0	0	5,189
- Commodity derivatives	69	(354)	(6,894)	(136)	12	0	(7,303)
- Exploration expenditure written off	177	1,270	0	0	0	0	1,447
Investments in associated companies	235	2,381	4,771	964	205	0	8,556
Other segment non-current assets*	151,503	95,980	30,103	25,171	2,873	0	305,630
Non-current assets, not allocated to segments**							18,462
Total non-current assets							332,648
Additions to PP&E and intangible assets***	29,200	28,900	3,200	2,500	500	0	64,300

* Excluding investments in associated companies

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

*** Excluding additions due to changes in estimated cost of abandonment and removal.

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 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, StatoilHydro has 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.

In the International Exploration and Production segment, the Group recognised an impairment loss of NOK 4.5 billion in 2008, 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 on the basis of their nature as intangible assets (exploration assets) and fixed assets (development and producing assets), respectively.

In 2007, the International Exploration and Production segment recognised an impairment loss of NOK 1.2 billion in 2007, of which the main part related to exploration and production assets (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.

Impairments of NOK 4.9 billion before tax in the International Exploration and Production segment in 2006 were related to Gulf of Mexico property, plant and equipment.

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

Geographical areas
StatoilHydro is present in 44 countries, and manages its four 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 2008, 2007 and 2006 is presented below:

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2008						
Norway	260,171	79,813	44,536	79,739	31,025	495,284
United States	24,712	8,795	1,660	20,182	2,545	57,894
Sweden	0	0	0	21,982	4,064	26,046
Denmark	0	0	0	21,170	(1,754)	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	159,958	40,688	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	52,772	14,107	386,673
United States	24,142	5,269	1,766	22,823	(864)	53,136
Sweden	0	0	0	16,378	6,731	23,109
Denmark	0	0	0	16,958	(2,038)	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	120,815	20,627	522,188

(in NOK million)	Crude oil	Gas	NGL	Refined products	Other	Total sale
Year ended 31 December 2006						
Norway	200,536	72,831	46,447	49,475	23,998	393,287
United States	21,070	3,731	2,089	17,436	1,296	45,622
Sweden	0	0	0	15,431	6,304	21,735
Denmark	0	0	0	14,552	87	14,639
Singapore	8,218	0	0	425	3	8,646
Other	10,768	7,157	3	15,999	2,947	36,874
Total revenues (excluding net income from associated companies)	240,592	83,719	48,539	113,318	34,635	520,803

Assets by geographic areas

(in NOK million)	2008	2007	2006
Norway	220,794	204,401	200,220
United States	50,587	38,672	33,841
Angola	23,807	15,906	16,371
Azerbaijan	21,396	16,279	17,444
Canada	17,151	14,423	3,160
Brazil	15,743	2,266	2,444
Algeria	11,270	8,371	9,699
Other areas	47,769	31,305	28,745
Non-current assets (excluding deferred tax asset, pension and financial non-current items) at 31 December	408,517	331,623	311,924

Major customers

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

8.1.6 Remuneration

(in NOK million, except number of man-labour year)	For the year ended 31 December 2008	2007	2006
Salaries	18,670	17,243	15,980
Pension cost*	2,851	3,131	2,281
Payroll tax	2,676	2,930	2,368
Other social benefits	2,102	1,997	1,567
Total payroll costs	26,299	25,301	22,196
Average man-labour year	28,001	27,641	26,899

*Pension cost for 2007 is exclusive of termination benefits.

Total payroll expenses are accumulated in cost-pools and partly charged to partners of StatoilHydro-operated licences on an hours incurred basis.

The calculation of pension costs and pension assets/liabilities is described in note 21 Pension liabilities.

Share based compensation
StatoilHydro's Share Saving Plan provides employees with the opportunity to purchase StatoilHydro shares through monthly salary deductions and a contribution by StatoilHydro. 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 StatoilHydro for purchased shares, amount vested for bonus shares granted and related social security tax was NOK 388, NOK 246 and NOK 96 million related to the 2008, 2007 and 2006 programs, respectively. For the 2009 program (granted in 2008) the estimated compensation expense is NOK 370 million. At 31 December 2008 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 773 million.

8.1.7 Other expenses

Auditors' remuneration

(in NOK million, excluding VAT)	Audit fee	Audit related and Other service fees	Total
2008			
Ernst & Young - Norway	35.0	5.0	40.0
Ernst & Young - outside Norway	25.3	3.9	29.2
Total	60.3	8.9	69.2
2007			
Ernst & Young - Norway	20.7	7.4	28.1
Ernst & Young - outside Norway	24.1	1.1	25.2
Total	44.8	8.5	53.3
2006			
Ernst & Young - Norway	15.9	4.2	20.1
Ernst & Young - outside Norway	19.9	2.4	22.3
Total	35.8	6.6	42.4

In addition to the figures in the table above for 2006 audit fee and other fees to Deloitte amount to NOK 39.4 and NOK 5.6 million, respectively and audit fees to Ernst & Young related to StatoilHydro-operated licenses amount to NOK 8.5, NOK 6.1 and NOK 4.0 million for 2008, 2007 and 2006, respectively.

The increases in audit fees and audit related and other fees from 2006 to 2007 and from 2007 to 2008 are mainly due to the increase in activity in connection with the merger with Hydro Petroleum.

Research and Development (R&D) expenditures

Research and Development (R&D) expenditures were NOK 2,243, NOK 1,969 and NOK 1,616 million in 2008, 2007 and 2006, respectively. R&D expenditures are partly financed by partners of StatoilHydro-operated licenses. StatoilHydro's share of the expenditures has been recognised as expense in the Consolidated statement of income.

8.1.8 Financial items

(In NOK million)	For the year ended 31 December 2008	2007	2006
Foreign exchange gains (losses) non-current financial liabilities	(11,252)	5,944	3,190
Foreign exchange gains (losses) derivative financial instruments	(25,001)	8,276	3,299
Other foreign exchange gains (losses)	3,690	(4,177)	(2,032)
Net foreign exchange gains (losses)	(32,563)	10,043	4,457
Dividends received	290	523	554
Gains (losses) financial investments	4,796	(723)	646
Interest income financial investments	975	338	612
Interest income non-current financial receivables	130	197	204
Interest and other financial income current financial assets	6,016	1,970	1,659
Interest income and other financial items	12,207	2,305	3,675
Capitalised borrowing costs	1,225	2,680	3,255
Accretion expense asset retirement obligation	(2,107)	(2,099)	(1,304)
Interest expense non-current financial liabilities	(2,743)	(2,795)	(3,059)
Gains (losses) derivative financial instruments	6,708	847	(365)
Interest and other financial expenses current financial liabilities	(1,092)	(1,374)	(1,587)
Interest and other financial expense	1,991	(2,741)	(3,060)
Net financial items	(18,365)	9,607	5,072

Included in the Foreign exchange gains (losses) derivative financial instruments classification are changes in the fair values of currency swap contracts related to liquidity and currency risk management. The weakening of the NOK versus the USD during 2008 resulted in fair value losses on these positions recognised in the annual figures for 2008.

Increase in Gains (losses) financial investments in 2008 is mainly related to currency effects, included in Fair value changes.

Increase in Interest and other financial income current financial assets in 2008 is mainly related to interest on currency swap contracts due to increased interest rate spread and accrued interest on prepaid tax.

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

Included in the Gains (losses) derivative financial instruments are changes in the fair values of swap positions which are used to manage the currency and interest rate risk on external loans. Decreasing USD interest rates during 2008 resulted in fair value gains on these positions. This resulted in a net financial income of NOK 2.0 billion reported on the Interest and other financial expenses classification in the annual figures for 2008.

The negative change in fair value of financial assets available for sale, included in non-listed equity securities in the balance sheet, recognised directly in equity was NOK 1,362 million in 2008, compared to a positive change in fair value of NOK 1,039 million in 2007 and a negative change in fair value of NOK 524 million in 2006.

8.1.9 Income taxes

Income before income taxes consists of

(in NOK million)	2008	2007	2006
Norway offshore	171,150	124,707	151,556
Norway onshore	(6,260)	7,331	6,402
Other countries upstream 1)	14,610	13,727	7,038
Other countries downstream 1)	967	1,046	6,240
Income before tax	180,467	146,811	171,236

Significant components of income tax expense were as follows

(in NOK million)	2008	2007	2006
Norway offshore	124,775	93,838	107,336
Norway onshore	3,378	1,924	1,149
Other countries upstream 1)	9,704	9,928	628
Other countries downstream 1)	306	535	5,434
Current income tax expense	138,163	106,225	114,547
Norway offshore	3,567	(555)	6,065
Norway onshore	(4,992)	373	856
Other countries upstream 1)	993	(3,688)	(2,669)
Other countries downstream 1)	(534)	(185)	589
Deferred tax expense	(966)	(4,055)	4,842
Income tax expense	137,197	102,170	119,389

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)	2008	2007	2006
Norway offshore	171,150	124,707	151,556
Norway onshore	(6,260)	7,331	6,402
Other countries upstream	14,610	13,727	7,038
Other countries downstream	967	1,046	6,240
Total income before tax	180,467	146,811	171,236
Calculated income taxes at statutory rates:			
Calculated income taxes at statutory rate (Norwegian statutory tax rate 28%)	50,531	41,107	47,946
Petroleum surtax at statutory rate (Norwegian special tax rate 50%)*	85,575	62,353	75,357
Uplift*	(5,047)	(4,365)	(3,759)
Other countries upstream (average statutory tax rates)	6,606	2,397	1,019
Other countries downstream (average statutory tax rates)	(497)	57	(754)
Other items	29	621	(420)
Income tax expense	137,197	102,170	119,389
Effective tax rate (%)	76.02	69.59	69.72

*Income from oil and gas activities on the NCS is taxed according to the Norwegian Petroleum Tax Act. In addition to normal corporation tax, a special tax of 50% is levied after deducting uplift, an investment tax credit. Uplift is deducted by 7.5% per year for four years, as from the year of investment. At the end of 2008 and 2007 unrecognised uplift credits amounted to NOK 15.1 and 17.3 billion, respectively.

The increase in the tax rate was mainly related to the net loss on financial items (mainly included in Norway onshore in the table above) which is tax deductible at a lower tax rate than the average rate.

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 2007									
Deferred tax assets	1,257	4,429	2,888	6,361	0	30,238	10,491	2,477	58,141
Deferred tax liabilities	0	(7,135)	0	(91,474)	(17,511)	0	0	(8,705)	(124,825)
Net asset/(liability) at 31 December 2007	1,257	(2,706)	2,888	(85,113)	(17,511)	30,238	10,491	(6,228)	(66,684)
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)

Analysis of movements during the year	2008	2007	2006
Deferred tax liability at 1 January	66,684	71,276	69,300
Charged/(credited) to the Consolidated statements of income	(966)	(4,055)	4,842
Charged/(credited) to Equity	802	175	(2,321)
Translation differences and other	322	(712)	(545)
Deferred tax liability at 31 December	66,842	66,684	71,276

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.

Following the internal group reorganisation effective 1 January 2009, see note 31 Merger with Hydro Petroleum, StatoilHydro ASA is no longer subject to the special petroleum tax. As a consequence, the tax assets related to pension liabilities in StatoilHydro ASA have effective 31 December 2008 been recognised at 28%, which is the tax rate expected to be in effect at the realisation date. Previously the estimated tax rate was 56%, based on assumed amounts expected to be realised under the petroleum tax regime and the general tax regime, respectively. The effect is a reduction of the deferred tax assets on pensions and retained earnings by NOK 5.4 billion as of 31 December 2008.

Deferred tax assets

At the end of 2008, StatoilHydro had recognised net deferred tax assets of NOK 1.3 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)	31 December 2008	31 December 2007
Deductible temporary differences	8,016	3,860
Tax losses carry forward	4,744	3,143

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.

8.1.10 Earnings per share

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.

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 2008, 2007 and 2006 respectively, calculated as follows:

	2008	2007	2006
Net income attributable to equity holders of the parent company (in NOK million)	43,265	44,096	51,117
Weighted average number of ordinary shares outstanding (in thousands of shares):			
Issued ordinary shares at 1 January	3,188,647	2,166,144	2,189,586
Effect of own shares held	(2,693)	(21,681)	(28,558)
Effect of shares issued in the merger with Hydro Petroleum	-	1,051,404	1,069,822
Weighted average number of ordinary shares	3,185,954	3,195,867	3,230,850
Earnings per share for income attributable to equity holders of the company - basic and diluted (NOK)	13.58	13.80	15.82

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.

8.1.11 Property, plant and equipment

(in NOK million)	Machinery, equipment and transportation equipment	Production oil and gas, plants incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Assets under development	Total
Cost at 31 December 2006	12,890	470,361	41,220	14,885	2,754	67,861	609,971
Additions and transfers	1,579	63,879	1,661	1,196	2,174	(15,158)	55,331
Disposals assets at cost	(230)	(2,829)	(162)	(1,161)	(160)	(23)	(4,565)
Effect of movements in foreign exchange - assets	(198)	(9,869)	(1,557)	(178)	(121)	(3,570)	(15,493)
Cost at 31 December 2007	14,041	521,542	41,162	14,742	4,647	49,110	645,244
Accumulated depr. and impairment losses at 31 December 2006	(9,200)	(295,391)	(24,956)	(5,606)	(386)	(2,269)	(337,808)
Depreciation, depletion and amortisation for the year	(889)	(33,875)	(1,356)	(660)	(230)	0	(37,010)
Impairment losses for the year	0	(1,470)	(105)	0	0	0	(1,575)
Accumulated depreciation and impairment disposed assets	174	2,820	118	618	158	(16)	3,872
Effect of movements in foreign exchange – depreciation	170	4,425	538	161	28	307	5,629
Accumulated depr. and impairment losses at 31 December 2007	(9,745)	(323,491)	(25,761)	(5,487)	(430)	(1,978)	(366,892)
Carrying amount at 31 December 2007	4,296	198,051	15,401	9,255	4,217	47,132	278,352
Estimated useful lives (years)	3 - 10	*	15-20	20 - 33	20 - 25		

(in NOK million)	Machinery, equipment and transportation equipment	Production oil and gas, plants 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, depletion and amortisation for the year	(1,005)	(36,872)	(1,607)	(672)	(396)	0	(40,552)
Transfers	0	(2,343)	0	0	0	2,343	0
Impairment losses for the year	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 2008 and 2007, capitalised borrowing cost amounted to NOK 1.2 and NOK 2.7 billion, respectively. In addition to depreciation, amortisation and impairment losses specified above, intangible assets, see note 12 Intangible assets, have been amortised by NOK 300 and NOK 787 million in 2008 and 2007, respectively.

Transfer of assets to Property, plant and equipment from Intangible assets in 2008 and 2007 amounted to NOK 1.5 and NOK 3.2 billion, respectively.

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

See note 5 Segments for description of asset impairments.

8.1.12 Intangible assets

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2006	26,096	6,830	32,926
Additions	23,237	742	23,979
Disposals intangible assets at cost	0	(191)	(191)
Transfers of intangible assets	(3,090)	(79)	(3,169)
Expensed exploration expenditures previously capitalised	(2,061)	0	(2,061)
Reversal of impaired exploration wells previously capitalised	134	0	134
Effect of movements in foreign exchange – intangible assets	(3,805)	(704)	(4,509)
Cost at 31 December 2007	40,511	6,598	47,109
Accumulated amortisation and impairment losses at 31 December 2006	0	(1,721)	(1,721)
Depreciation, impairments and amortisation for the year	0	(787)	(787)
Disposals amortisation and impairment losses	0	191	191
Effect of movements in foreign exchange - amortisation and impairment losses	0	58	58
Accumulated amortisation and impairment losses at 31 December 2007	0	(2,259)	(2,259)
Carrying amount at 31 December 2007	40,511	4,339	44,850

(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 – intangible assets	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	0	(2,259)	(2,259)
Depreciation, impairments and amortisation for the year	0	(300)	(300)
Disposals amortisation and impairment losses	0	1,686	1,686
Effect of movements in foreign exchange - amortisation and impairment losses	0	(110)	(110)
Accumulated amortisation and impairment losses at 31 December 2008	0	(983)	(983)
Carrying amount at 31 December 2008	61,488	4,548	66,036

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematicaly over their estimated economic lives, ranging between 10-20 years.

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 Significant acquisitions and dispositions for details on the acquisitions during 2008. For 2007, acquisition of assets from Anadarko Petroleum Corporation and North American Oil Sands Corporation were included in this line in addition to other exploration activity capitalised during 2007.

Included in Other Intangibles is goodwill of NOK 3 billion at 31 December 2008.

Impairment charges of NOK 2.4 billion relates to impairments of capitalised exploration mainly in the Gulf of Mexico and is classified as exploration expenses in the Statement of income. Amortisation and impairment charges relating to other intangible assets are recognised as depreciation, amortisation and impairment losses in the Consolidated statement of income. Reference is made to information in note 2 - Significant accounting policies, regarding method and assumptions used in impairment tests performed.

8.1.13 Investments in associated companies

(in NOK million)	2008	2007
Carrying amount associated companies at 31 December	12,640	8,421
Net income (loss) from associated companies	1,283	609

The most significant associated companies included in the table above are South Caucasus PHC Ltd (ownership share 25,5%), BTC Pipeline company (ownership share 8,71%) and Petrocedeño S.A (ownership share 9,68%). Through contractual agreements the group has significant influence also over the BTC Pipeline company and Petrocedeño S.A, and consequently the ownership interests in these companies are accounted for using the equity method.

8.1.14 Non-current financial assets

Non-current financial investments

	At 31 December	
(in NOK million)	2008	2007
Commercial papers	0	605
Bonds	9,984	7,140
Listed equity securities	2,276	4,230
Non-listed equity securities	4,205	3,291
Financial investments	16,465	15,266

Of the non-current financial investments, NOK 12,301 million relate to the investment portfolio held by the group's captive insurance subsidiary and is accounted for using the fair value option. NOK 80 million of the group's captive insurance subsidiary portfolio is used as collateral for trading with OTC instruments.

StatoilHydro's acquisition of the Jet automated petrol retail station network was approved by the European Commission (EC) in October 2008. At 31 December 2008 it has been classified as non-listed equity securities in the balance sheet, in accordance with IAS 39, caused by certain divestment requirements set out by the EC which implies holding the activity ringfenced and thereby without StatoilHydro retaining the control prior to fulfilling the divestment requirement.

All non-current financial investments are measured at fair value. Fair value changes for non-listed equity securities are recognised in Equity - other reserves. Fair value changes for Commercial papers, Bonds and Listed equity securities are recognised in the statement of income.

When an active market exists, financial instruments are valued on the basis of quoted prices. The following table summarises the source for the group's fair value measurement of the non-current financial investments. Of the total fair value of NOK 6,402 million that is measured based on prices quoted in an active market, NOK 4,126 million are government bonds.

Source of fair value (in NOK million)	Commercial papers	Bonds	Listed equity securities	Non-listed equity securities	Total fair value
At 31 December 2008					
Fair value based on prices quoted in active market	-	4,126	2,276	-	6,402
Fair value based on price inputs from observable market transactions	-	5,858	-	717	6,575
Fair value based on inputs from other sources	-	-	-	3,488	3,488
Total fair value	-	9,984	2,276	4,205	16,465
At 31 December 2007					
Fair value based on prices quoted in active market	-	3,377	4,230	-	7,607
Fair value based on price inputs from observable market transactions	605	3,763	-	373	4,741
Fair value based on inputs from other sources	-	-	-	2,918	2,918
Total fair value	605	7,140	4,230	3,291	15,266

The table below contains the fair value and related equity price risk sensitivity of our listed and non-listed equity instruments, as accounted for under IAS 39. In 2008 the sensitivities have been calculated by using a 20% change for Listed equity securities and 40% change for Non-listed equity securities. Compared to the sensitivity calculated for 2007 the group's view of what is assessed to be reasonable possible changes for the coming year has been updated due to the changes taking place in the financial market.

Equity risk

(in NOK million)	Fair value	-20% sensitivity	20% sensitivity
At 31 December 2008			
Listed equity securities	2,276	(455)	455

(in NOK million)	Fair value	-40% sensitivity	40% sensitivity
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

Non-current financial receivables

(in NOK million)	At 31 December 2008	2007
Interest bearing receivables	2,736	2,784
Non-interest bearing receivables	2,178	731
Financial receivables	4,914	3,515

Of the interest bearing receivables at 31 December 2008 a balance of NOK 1,070 million relates to the BTC project financing structure and NOK 1,145 million relates to the PetroCedeño project financing structure. The receivable related to PetroCedeno SA is subordinated to the bank loan, if PetroCedeno SA is in default. Corresponding balances for 31 December 2007 were NOK 934 million for BTC and NOK 1,086 million for PetroCedeño.

Of the non-interest bearing receivables at 31 December 2008 NOK 1,024 relates to a reimbursement of a contingent liability pending the settlement of a dispute in which StatoilHydro is not a direct part. The contingent liability is included in other provisions.

All non-current financial receivables are classified in the loan and receivables category and carrying amounts reasonably approximate fair value. The following table summarises the source for the group's fair value measurement of the non-current financial receivables.

Source of fair value (in NOK million)	Interest bearing receivables	Non-interest bearing receivables	Total fair value
At 31 December 2008			
Fair value based on prices quoted in active market	-	-	-
Fair value based on price inputs from observable market transactions	2,736	998	3,734
Fair value based on inputs from other sources	-	1,180	1,180
Total fair value	2,736	2,178	4,914
At 31 December 2007			
Fair value based on prices quoted in active market	-	-	-
Fair value based on price inputs from observable market transactions	2,784	691	3,475
Fair value based on inputs from other sources	-	40	40
Total fair value	2,784	731	3,515

8.1.15 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)	2008	2007
Crude oil	7,249	8,097
Petroleum products	6,338	7,186
Other	1,564	2,413
Inventories	15,151	17,696

A write-down of inventory to net realisable value of NOK 3.9 billion has been recognised as Purchases [net of inventory variation] at year end 2008 (0 at year end 2007).

8.1.16 Trade and other receivables

(in NOK million)	At 31 December 2008	2007
Trade receivables	61,083	62,060
Receivables joint ventures	7,131	6,115
Receivables associated companies and other related parties	1,717	1,203
Trade and other receivables	69,931	69,378

8.1.17 Current financial investments

Current financial investments

(in NOK million)	At 31 December 2008	2007
Commercial papers	7,131	3,204
Money market funds	2,602	155
Other	14	0
Financial investments	9,747	3,359

All balances at are classified as held for trading investments, except from NOK 1,858 million at 31 December 2008 related to the investment portfolio held by the group's captive insurance subsidiary which is accounted for using fair value option.

All current financial investments are measured at fair value with gains and losses recognised in the Consolidated statements of income. When an active market exists, financial instruments are valued on the basis of quoted prices. The following table summarises the source for the group's fair value measurement of the financial instruments.

Source of fair value (in NOK million)	Commercial papers	Money market funds	Other	Total fair value
At 31 December 2008				
Fair value based on prices quoted in active market	1,744	-	-	1,744
Fair value based on price inputs from observable market transactions	5,387	2,602	14	8,003
Fair value based on inputs from other sources	-	-	-	-
Total fair value	7,131	2,602	14	9,747
At 31 December 2007				
Fair value based on prices quoted in active market	-	-	-	-
Fair value based on price inputs from observable market transactions	3,204	155	-	3,359
Fair value based on inputs from other sources	-	-	-	-
Total fair value	3,204	155	-	3,359

8.1.18 Cash and cash equivalents

(in NOK million)	At 31 December 2008	2007
Cash at bank	12,165	3,837
Time deposits and collateral deposits	6,473	14,427
Cash and cash equivalents	18,638	18,264

Cash and cash equivalents at 31 December 2008 include restricted cash of NOK 4,073 million related to trading activities. 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 under note 24 Current financial liabilities. For reconciliation of Cash and cash equivalents reported in the statement of financial position, see Consolidated statements of cash flows.

8.1.19 Shareholders equity

							Other reserves				
(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Available for sale financial assets	Currency translation adjustments	StatoilHydro shareholders' equity	Minority interest	Total
At 1 January 2006	3,232,247,836	8,081	(60)	44,623	(96)	101,518	727	0	154,793	1,592	156,385
Net income for the period						51,117			51,117	730	51,847
Income and expense recognised directly in equity						(958)	(277)	(3,817)	(5,052)		(5,052)
Total recognised income and expense for the period*											46,795
Dividend paid						(17,756)			(17,756)		(17,756)
Cash distributions (to) from minority shareholders										(748)	(748)
Reduction of share capital	(23,441,885)	(59)	59						0		0
Merger related adjustments consist of change in merger balance with Norsk Hydro ASA						(11,768)			(11,768)		(11,768)
Equity settled share based payments				61					61		61
Treasury shares purchased (net of allocated shares)			(53)		(3,509)				(3,562)		(3,562)
At 31 December 2006	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 equity						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 minority shareholders										(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

(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	StatoilHydro shareholders' equity	Minority interest	Total
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 equity						(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 minority shareholders										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

* For detailed information, see Consolidated statements of recognised income and expense.

The NOK 9,094 million reduction in retained earnings in 2008, in the line item Income and expense recognised directly in equity, consist of actuarial losses, net of increase in the related deferred tax asset of NOK 3,704 million, and a reduction in deferred tax assets of NOK 5,390 million due to internal reorganisations, see note 32 Subsequent events for more details on the reorganisations.

The currency translation adjustments in 2008, on the line item Income and expense recognised directly in equity, relates to the translation of significant net assets amounts in subsidiaries, mainly whose functional currencies are USD and EUR, and are caused by the weakening of the NOK to the USD and EUR.

For information regarding changes in equity related to the merger with Hydro Petroleum, see information in note 31 Merger with Hydro Petroleum.

In 2001, 25,000,000 treasury shares were issued. During 2002 and 2003 a total of 1,558,115 of the treasury shares were distributed as bonus shares in favour of retail investors in the initial public offering in 2001. On 10 May 2006 the annual General Meeting resolved to reduce the company's share capital by a total of NOK 58,604,712.50 through the annulment of the rest of these treasury shares.

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 2008 the Norwegian State had an ownership interest in StatoilHydro of 66.42% (excluding Folketrygdfondet of 3.42% (Norwegian national insurance fund)). The Norwegian State is defined as a related party, see note 27 Related parties.

After the annulment in 2007, StatoilHydro's 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 StatoilHydro shares in the market. The authorisation may be used to acquire StatoilHydro shares with an overall nominal value of up to NOK 15 million. The Board decides the manner in which the acquisition of StatoilHydro shares in the market will take place. Such shares acquired in accordance with the authorisation may only be used for sale and transfer to employees of the StatoilHydro Group as part of the Group's share saving plan approved by the Board. The lowest amount which may be paid per share is NOK 50, the highest amount which may be paid per share is a maximum NOK 500. The authorisation is valid until the next ordinary General Meeting.

During 2008 a total of 2,106,223 treasury shares were purchased for NOK 308 million. At 31 December 2008 StatoilHydro had 3,781,209 treasury shares all of which are related to the group's share saving plan.

StatoilHydro 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 8.50 in 2008 for StatoilHydro ASA and NOK 9.12 and NOK 8.20 in 2008, 2007 and 2006, 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 StatoilHydro's equity include both the former Statoil ASA and Hydro Petroleum dividend payments. A dividend for 2008 of NOK 7.25 per share, amounting to a total dividend of NOK 23.1 billion, will be proposed at the Annual General Meeting in May 2009. The proposed dividend is not recognised as a liability in the financial statements.

Retained earnings available for distribution of dividends at 31 December 2008 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 120,168 million (before provisions for proposed dividend for the year ended 31 December 2008 of NOK 23,090 million). This differs from retained earnings in the consolidated financial statements of NOK 147,998 million. In accordance with legal requirements dividends is not allowed to reduce the shareholders' equity of the parent company below 10% of total assets.

8.1.20 Non-current financial liabilities

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	
	2008	2007	2008	2007	2008	2007
Financial liabilities measured at amortised cost						
Unsecured bonds						
US dollar (USD)	6.78	7.00	24,202	17,418	25,709	20,016
Norwegian kroner (NOK)	-	6.21	-	500	-	501
Euro (EUR)	5.58	5.62	6,101	5,316	6,458	5,634
Swiss franc (CHF)	4.01	-	1,023	-	1,032	-
Japanese yen (JPY)	1.65	1.50	1,008	869	983	878
Great Britain Pound (GBP)	6.13	6.13	2,271	2,429	1,935	2,543
Total (A)			34,605	26,532	36,117	29,572
Unsecured bank loans						
US dollar (USD)	2.60	5.09	6,314	2,530	6,329	2,549
Secured bank loans						
US dollar (USD)	5.86	7.45	1,252	2,683	1,262	2,792
Other currencies	6.82	6.57	63	80	63	80
Financial lease liabilities			5,665	4,011	5,665	3,738
Other liabilities			864	38	855	38
Total (B)			14,158	9,342	14,174	9,197
Financial liabilities measured at amortised cost subject for hedge accounting						
US dollar (USD)	5.94	6.29	9,957	7,845	7,403	7,849
Euro (EUR)	5.13	5.13	2,097	1,627	2,050	1,636
Swiss franc (CHF)	-	4.01	-	982	-	979
Japanese yen (JPY)	-	0.47	-	241	-	241
Total (C)			12,054	10,695	9,453	10,705
Grand total liabilities outstanding (A+B+C)			60,817	46,569	59,744	49,474
Less current portion			6,211	2,196	6,183	2,196
Financial liabilities			54,606	44,373	53,561	47,278

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. The table does not illustrate the economic effects of agreements entered into to swap the various currencies into USD. For further information see note 29 Financial instruments by category.

Weighted average interest rates are calculated on the loans per currency 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.

Details of largest unsecured bonds

Bond agreement	Fixed interest rate	Maturity (year)	Carrying amount in NOK million at 31 December 2008	2007
USD 500 million	6.500%	2028	3,462	2,675
USD 500 million	5.125%	2014	3,498	2,704
USD 480 million	7.250%	2027	3,363	2,600
USD 375 million	5.750%	2009	2,624*	2,026*
USD 300 million	7.750%	2023	2,100	1,623
USD 300 million	6.360%	2009	2,100	1,623
EUR 500 million	5.125%	2011	4,915	3,961
EUR 300 million	6.250%	2010	2,960	2,388
GBP 225 million	6.125%	2028	2,277	2,432

* Net after buy-backs NOK 2,288 million and NOK 1,765 million in 2008 and 2007, respectively.

Currency swaps are used for risk management purposes. Unsecured bonds are either denominated in US dollar, amounting to NOK 34,159 million or the amounts are swapped into US dollar, amounting to NOK 12,500 million. As a result of this the total portfolio is exposed to changes in the USDNOK exchange rate. None of the US dollar currency swaps entered into as economic hedges meet the criteria for hedge accounting. Interest rate swaps are used to manage the interest rate risk on the unsecured bond contracts with fixed interest rates. As a result of this 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 2,908 million, collateral in bank deposits with book value of NOK 1,070 million, and the group's pro-rata share of income from certain applicable projects.

The group has 24 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 is NOK 42,722 million at the 31 December 2008 closing rate.

The group has an agreement with an international bank syndicate for a committed non-current revolving credit facility totalling USD 2.0 billion, all undrawn at the 31 December 2008. The commitment fee is 0.0575% per annum.

Non-current financial liabilities maturity profile

(undiscounted cash flows in NOK million)	At 31 December 2008	2007
1-3 years	14,635	13,112
3-5 years	14,095	13,651
After 5 years	53,324	46,438
Total repayment of non-current financial liabilities	82,055	73,201

Financial liabilities

	At 31 December 2008	2007
Non-current financial liabilities (in NOK million)	54,606	44,373
Weighted average maturity (years)	9	10
Weighted average annual interest rate (%)	5.64	6.11

8.1.21 Pension liabilities

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

StatoilHydro 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 the group have defined contribution plans. The period's contributions are recognised in the Consolidated Statements of Income as the pension cost for the period.

In Norway, the group is - due to National agreements - a member of the "agreement-based early retirement plan" (AFP). When an employee retires through AFP the group has an obligation to pay a percentage of the benefits. This part of the plan is defined as a multi-employer plan. The administrator is not able to calculate the group's share of assets and liabilities and this plan is consequently accounted for as a defined contribution plan. When an employee retires through AFP, the group also offers a gratuity from the company. This is a defined benefit plan, and included in the accrued obligations related to the defined benefit plans.

The obligations related to the defined benefit plans were measured at 31 December, 2008 and 2007. 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 2008 the discount rate for the defined benefit plans in Norway was estimated to be 4.5% based on the long-term interest rate on Norwegian government bonds extrapolated based on a 30 year yield curve to match StatoilHydro's payment portfolio for earned benefits.

The longest duration of Norwegian government bonds are 10 years. It is StatoilHydro's opinion that the most appropriate method to extrapolate the 10 years rate to a 30 year rate is based on the yield curves with reference to European and USA interest rates (equally weighted). In a long term perspective, these countries are assumed to have similar market trends and interest levels as Norway.

Actuarial gains and losses are recognised directly in retained earnings, outside the Consolidated Statements of Income, in the period in which they occur, and are presented in the statement of recognised income and expense. Actuarial gains and losses related to the accrual for termination benefits are recognised in the Consolidated Statements of Income in the period in which they occur.

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

StatoilHydro 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)	2008	2007	2006
Current service cost	2,361	2,611	2,065
Interest cost on prior years' benefit obligation	2,456	1,713	1,421
Expected return on plan assets	(2,101)	(1,829)	(1,407)
Amortisation of actuarial gain or loss related to termination benefits	(215)	0	0
Amortisation of past service cost	17	2,075	0
Losses (gains) from curtailment or settlement	(7)	(1,641)	0
Defined benefit plans	2,511	2,929	2,079
Defined contribution plans	268	160	155
Multi-employer plans	72	42	47
Termination benefits	0	8,633	49
Net pension cost	2,851	11,764	2,330

Pension cost includes payroll tax.

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

For information regarding pension benefits for key management personnel, see note 27 Related parties.

In 2007, StatoilHydro 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 administration expenses, respectively.

Change in projected benefit obligation (PBO)

(in NOK million)	2008	2007
Projected benefit obligation at 1 January	52,791	40,185
Current service cost	2,361	2,611
Interest cost on prior years' benefit obligation	2,456	1,713
Actuarial loss (gain)	3,581	198
Past service cost	18	2,075
Benefits paid	(1,302)	(605)
Curtailments	0	(1,641)
Early retirement	0	8,633
Sale of subsidiary	(670)	0
Settlement	0	(329)
Foreign currency translation	(29)	(49)
Projected benefit obligation at 31 December	59,206	52,791

Change in pension plan assets

(in NOK million)	2008	2007
Fair value of plan assets at 1 January	35,158	30,110
Expected return on plan assets	2,101	1,829
Actuarial gain (loss)	(4,149)	(236)
Company contributions (including payroll tax)	1,377	3,777
Benefits paid	(346)	(338)
Sale of subsidiary	(443)	11
Foreign currency translation	0	5
Fair value of plan assets at 31 December	33,698	35,158

Change in net pension liabilities

(in NOK million)	2008	2007
Net pension liabilities at 1 January	(17,633)	(10,078)
Net periodic pension costs defined benefit plans	(2,511)	(2,929)
Net actuarial loss (gain) recognised in SORIE	(7,945)	(434)
Less employer contributions	1,377	3,777
Less benefit paid during the year	956	259
Acquisition and sale	227	11
Settlement	0	340
Foreign currency translation and other changes	21	54
Termination benefits	0	(8,633)
Net pension liabilities at 31 December	(25,508)	(17,633)

Surplus (deficit) at 31 December for the current and previous two periods are as follow:

(in NOK million)	2008	2007	2006
Surplus (deficit) at 31 December	(25,508)	(17,633)	(10,078)
Represented by:			
Asset recognised as pension asset	30	1,622	1,113
Liability recognised as non-current pension liability	(25,538)	(19,092)	(11,028)
Liability recognised as current liability	0	(163)	(163)

The defined benefit obligation may be analysed as follows:

(in NOK million)	2008	2007
Funded pension plans	37,446	33,278
Unfunded pension plans	21,760	19,513
Projected benefit obligation at 31 December	59,206	52,791

Actuarial gains and losses recognised directly in retained earnings:

(in NOK million)	2008	2007	2006
Unrecognised actuarial losses (gains) at 1 January	0	0	0
Actuarial losses (gains) on plan assets occur during the year	4,149	(272)	(1,139)
Actuarial losses (gains) on benefit obligation occur during the year	3,581	198	4,169
Recognised in the income statement during the year	215	0	0
Recognised in SORIE during the year	(7,945)	74	(3,030)
Unrecognised actuarial losses (gains) at 31 December	0	0	0

Actual return on plan assets

(in NOK million)	2008	2007	2006
Actual return on plan assets	(2,048)	1,593	2,546

History of experience gains and losses for the current and previous two periods are as follow:

(in NOK million)	2008	2007	2006
Actual return less expected return on plan assets (NOK million)	(4,149)	272	1,139
As % of plan assets at beginning of year	(11.80%)	0.90%	4.45%
Experience gains/(losses) on plan liabilities (NOK million)	(3,581)	(198)	(4,169)
As % of present value of plan liabilities at beginning of year	(6.78%)	(0.49%)	(12.60%)
Total actuarial gain/(loss) (NOK million)	(7,730)	74	(3,030)
As % of present value of plan liabilities at beginning of year	(14.64%)	0.25%	(9.16%)

The cumulative amount of actuarial gains and losses recognised in the Statement of recognised income and expense amounted to NOK 13.3, NOK 4.2 billion and NOK 4.5 billion net of tax (negative effect on retained earnings) in 2008, 2007 and 2006, respectively.

Assumptions for the year (Profit and Loss items) in %	2008	2007
Discount rate	5.00	4.50
Expected return on plan assets	6.25	5.75
Rate of compensation increase	4.50	4.25
Expected rate of pension increase	3.25	2.75
Expected increase of social security base amount (G-amount)	4.25	4.00
Expected Inflation	2.25	2.25

Assumptions at end of year (Balance sheet items) in %	2008	2007
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
Average remaining service period in years	15	15

The assumptions presented are for the Norwegian companies in the group which are members of StatoilHydro's pension fund. The defined benefit plans of other subsidiaries are not significant to the pension assets and liabilities of the group.

Expected turnover 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 turnover at 31 December 2007 was 4.0%, 1.5%, 1.3%, 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 employees at 63-66 years.

For the population in Norway, the mortality table K 2005 plus one extra year of living 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 StatoilHydro in Norway.

Below is shown a selection related to demographic assumptions used at 31 December 2008. 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	0.015	0.015	81.51	85.35
40	0.21	0.35	0.083	0.046	81.83	85.60
60	1.48	1.94	0.716	0.386	83.27	86.51
80	N/A	N/A	6.550	4.142	88.97	90.74

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 2008. 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)	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%	0.5%	-0.5%
Changes in:								
Projected benefit obligation at 31 December 2008	(4.8)	5.5	3.9	(3.5)	(1.5)	1.5	3.1	(2.8)
Service cost 2009	(0.3)	0.4	0.3	(0.3)	(0.1)	0.1	0.2	(0.2)

Pension assets

The plan assets related to the defined benefit plans were measured at fair value at 31 December 2008 and 2007. The long-term expected return on pension assets is based on long-term risk-free rate adjusted for the expected long-term risk premium for the respective investment classes. A risk free interest (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 %)	2008	2007
Equity securities	19.10	31.90
Debt securities	70.20	50.50
Commercial papers	3.30	8.60
Real estate	6.90	6.90
Other assets	0.50	2.10
Total	100.00	100.00

Properties owned by StatoilHydro pension fund amounted to NOK 2.2 billion and NOK 2.3 billion of total pension assets at 31 December 2008 and 2007, respectively, and are rented to companies in the group.

StatoilHydro'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 StatoilHydro pension fund for 2009. The portfolio weight during a year will depend on the risk capacity.

Finance portfolio StatoilHydro's pension fund

(All figures in %)	Portfolio weight 1)		Expected rate of return
Equity securities	40.00	(+/- 5)	X + 4
Debt securities	59.50	(+/- 5)	X
Certificates	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 4.5 billion and NOK 7.3 billion at 31 December 2008 and 2007, respectively. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. 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 payroll tax). In addition, NOK 1.2 billion was paid to StatoilHydro pension fund as a capital increase in 2008. In 2007, the company contribution, paid in cash, was NOK 3.4 billion (exclusive payroll tax) of which NOK 1.0 billion was a voluntary payment to the premium fund.

The expected company contribution related to 2009 amounts to NOK 2.5 billion.

8.1.22 Asset retirement obligations, other provisions and other liabilities

(in NOK million)	
Asset retirement obligations at 1 January 2007	39,912
Liabilities incurred/revision in estimates	(1,644)
Amounts used and charged against provision	(636)
Unused amounts reversed	0
Effects of change in the discount rate	443
Reduction due to disposals	(120)
Accretion	2,099
Currency exchange difference	(473)
Asset retirement obligations at 31 December 2007	39,581
Current portion of asset retirement obligations	575
Analysis of provisions and other liabilities at 31 December 2007:	
Non-current portion of asset retirement obligations	39,006
Other provisions and other liabilities	4,839
Asset retirement obligations, other provisions and other liabilities	43,845
Asset retirement obligations at 1 January 2008	39,581
Liabilities incurred/revision in estimates	5,470
Amounts used and charged against provision	(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 and other liabilities	11,178
Asset retirement obligations, other provisions and other liabilities	54,359

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.

8.1.23 Trade and other payables

(in NOK million)	At 31 December 2008	2007
Trade payables	15,582	21,776
Non-trade payables, accrued expenses and provisions	38,155	29,918
Payables to associated companies and other related parties	7,463	12,930
Trade and other payables	61,200	64,624

Non-trade payables and accrued expenses include provisions for certain claims and litigations that are further described in note 26 Other commitments and contingencies.

8.1.24 Current financial liabilities

(in NOK million)	At 31 December 2008	2007
Current financial liabilities measured at amortised cost		
Bank loans and overdraft facilities	906	1,100
Collateral liabilities	10,123	2,797
Commercial paper liabilities	2,989	0
Current portion of non-current financial liabilities	5,604	1,919
Current portion of financial lease obligations	607	277
Other	466	73
Financial liabilities	20,695	6,166
Weighted interest rate	2.50%	5.56%

Current financial liabilities' carrying amounts reasonably approximate fair value. Fair value is based on price inputs from observable markte transactions.

Collateral liabilities relates to cash received in order to offset a portion of the group credit exposure.

Commercial paper liabilities relates to the US Commercial Paper (CP) program available for short term funding. StatoilHydro can borrow maximum USD 4 billion under the current CP programme.

At 31 December 2008 and 2007 the group had no committed short-term credit facilities available or drawn.

8.1.25 Leases

StatoilHydro leases certain assets, notably vessels and drilling rigs.

StatoilHydro has entered into certain operational lease contracts for a number of drilling rigs as of 31 December 2008. The remaining significant contracts' terms range from three months to five years. Certain contracts contain renewal options. Rig lease agreements are for the most part based on fixed day rates. StatoilHydro'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 StatoilHydro-operated licenses on the Norwegian Continental Shelf (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, StatoilHydro only includes its proportional share of the rig lease.

As a member of the Snøhvit sellers' group StatoilHydro has entered into leasing arrangements for three LNG vessels on behalf of StatoilHydro and the SDFI respectively. StatoilHydro accounts for the combined StatoilHydro and the SDFI share of these agreements as financial 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 a leasing term of 20 years. In addition, StatoilHydro has the option to extend the leases for two additional periods of five years each.

In 2008, net rental expense was NOK 10.2 billion (NOK 5.7 billion in 2007 and NOK 4.9 billion in 2006) of which minimum lease payments were NOK 11.8 billion (NOK 7.1 billion in 2007 and NOK 5.9 billion in 2006) and sublease payments received were NOK 1.7 billion (NOK 1.5 billion in 2007 and NOK 1.0 billion in 2006). No material contingent rents expensed in 2008, 2007 or 2006.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2008.

Amounts related to financial leases include future minimum lease payments for assets in the financial statements at year-end 2008.

			Financial lease		
(in NOK million)	**Operating leases**	**Operating subleases**	**Minimum lease payments**	**Interest**	**Net present value minimum lease payments**
2009	16,101	(2,161)	742	(101)	641
2010	13,400	(1,274)	684	(110)	574
2011	9,107	(138)	700	(115)	585
2012	6,383	(131)	694	(107)	587
2013	4,375	(131)	469	(108)	361
Thereafter	3,955	(1,203)	4,731	(1,815)	2,916
Total future minimum lease payments	53,321	(5,038)	8,020	(2,356)	5,664

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2008 and 2007:

(in NOK million)	**2008**	**2007**
Vessels and equipment	6,501	5,503
Accumulated depreciation	(1,205)	(836)
Capitalised amount	5,296	4,667

8.1.26 Other commitments and contingencies

Contractual commitments

(in NOK million)	2009	2010	Thereafter	Total
Joint Venture related:				
Construction in progress	12,005	5,559	3,866	21,430
Property, plant and equipment and other investments	3,161	4,176	10,110	17,447
Acquisition of intangible assets	2,881	173	15	3,069
Subtotal joint venture related commitments	18,047	9,908	13,991	41,946
Non Joint Venture related:				
Construction in progress	3,004	2,150	309	5,463
Total	21,051	12,058	14,300	47,409

The contractual commitments reflect StatoilHydro's share and mainly comprise construction and acquisition of property, plant and equipment.

Other long-term commitments

StatoilHydro 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 31 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 unconsolidated equity associates are included gross in the tables below. Where the group reflects both ownership interests and transport capacity cost for a pipeline or other asset in the consolidated accounts, the amounts in the table include the net commitment payable for StatoilHydro.

Nominal minimum commitments at 31 December 2008:

(in NOK million)	Transport and terminal commitments	Refinery related commitments	Total
2009	7,847	127	7,974
2010	7,851	262	8,113
2011	8,201	271	8,472
2012	7,310	292	7,602
2013	6,196	314	6,510
Thereafter	41,653	21,561	63,214
Total	79,058	22,827	101,885

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

StatoilHydro has contractual commitments to the US-based energy company Dominion for terminal capacity at the Cove Point liquefied natural gas terminal in the USA. As of 2009 the commitment will include an annual capacity of approximately 10.1 bcm for a 20 year period. 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. StatoilHydro's and the SDFI's respective future shares of the Cove Point terminal capacity and related commitments are subject to future consideration, and the outcome may consequently impact the extent of the future net terminal capacity and related net commitments assumed by StatoilHydro.

In 2008 Sonatrach and StatoilHydro signed an agreement under the terms of which Sonatrach will receive access to an annual of 2 bcm of StatoilHydro's regasification capacity at the Cove Point terminal for 15 years from the beginning of 2009. This arrangement which reduces StatoilHydro's net exposure at the Cove Point terminal has however not been substracted from the above table.

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.

StatoilHydro 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 Detaljhandel has issued guarantees amounting to a total of SEK 1.0 billion (NOK 0.9 billion), the main part of which relates to financial guarantee commitments on behalf of retailers. The liability recognized at fair value under IAS 39 related to these guarantee commitments is immaterial at year end.

StatoilHydro 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, StatoilHydro is obligated to deliver indemnity reserves to Petro Canada in the event that recoverable reserves prove lower than a specified volume. At year end 2008 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 2.1 billion at current market prices. A provision of NOK 0.8 billion has been recognised at year end 2008 related to this guarantee.

Under the Norwegian public limited companies act section 14-11, StatoilHydro 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 StatoilHydro is jointly liable for is approximately NOK 6.6 billion with terms extending until 2050. As of the current date, the probability that these guarantee commitments will impact StatoilHydro is deemed to be remote. No liability has been recognised in the accounts at year end 2008.

Insurance

The group has taken out insurance to cover certain potential liabilities arising from its operations world wide. This covers 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. relates to insurance for entities and operations consolidated in the group accounts, 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 2008, StatoilHydro was committed to participate in 22 wells in Norway and 53 wells outside Norway, with an average ownership interest of approximately 46%. StatoilHydro's share of estimated expenditures to drill these wells amounts to approximately NOK 12 billion. Additional wells that StatoilHydro may become committed to participate in depending on future discoveries in certain licenses are not included in these numbers.

StatoilHydro 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 StatoilHydro 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 on 29 April 2008 issued a writ involving a multi-component compensation claim, the aggregate principal exposure of which for StatoilHydro approximates between NOK 4 and 7 billion after tax. In November 2008 ExxonMobil, the final Åsgard partner at the time of the original dispute, has issued a similar writ with a compensation claim approximating an estimated exposure of up to NOK 1 billion after tax. StatoilHydro rejects both claims.

The price reviews of two long-term natural gas contracts previously in arbitration have been settled during 2008 without any significant effect on the income statement.

StatoilHydro ASA has offered early retirement packages to employees above the age of 58 years (contingent upon certain conditions). The offer is divided into two phases; employees working onshore (first phase) and employees working offshore and on onshore plants and terminals (second phase). A settlement concerning restructuring cost charges related to the first phase has been reached between StatoilHydro and the partners on the Norwegian continental shelf, see further in note 5 Segments. Contingent receivables related to the second phase remain unrecorded.

StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's petroleum activities in Libya, which were transferred to StatoilHydro 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 StatoilHydro, 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 StatoilHydro 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 StatoilHydro ASA may be subject as a result of the merger.

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

8.1.27 Related parties

Transactions with the Norwegian State
The Norwegian State is the majority shareholder of StatoilHydro and also holds major investments in other entities. This ownership structure means that StatoilHydro 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 arms-length basis.

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

Total purchases of oil and natural gas liquid from the Norwegian State amounted to NOK 112,682 million, (223 million barrels oil equivalents), NOK 98,498 million (237 million barrels oil equivalents) and NOK 104,628 (254 million barrels oil equivalents) in 2008, 2007 and 2006, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licenses) amounted to NOK 375 million, NOK 287 million and NOK 293 million in 2008, 2007 and 2006, respectively. The significant amounts included in the line item Payables to associated companies and other related parties in Trade and other payables, see note 23 Trade and other payables, are amounts payable to the Norwegian State for these purchases.

The State's natural gas production, which StatoilHydro 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 net in StatoilHydro's financial statements.

Other transactions
In relation to its ordinary business operations such as pipeline transport, gas storage and processing of petroleum products, StatoilHydro 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 Executive Committee) during the year was as follows:

(in NOK thousand)	2008	2007	2006
Current benefits	50,949	44,463	41,602
Post-employment benefits	12,534	12,764	13,938
Other non-current benefits	129	111	135
Share based payment benefits	278	94	40
Total	63,890	57,432	55,715

Loans to key management total less than NOK 0.3 million.

8.1.28 Financial risk management

General information relevant to risks

StatoilHydro's business activities naturally expose the group to 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 (i.e. utilize the natural hedges embedded in our portfolio). This approach also reduces the number of unnecessary transactions (i.e. reducing transaction costs and avoiding sub-optimisation).

In order to achieve the above effects, the group has centralized trading mandates such that all major/strategic transactions are co-ordinated through our Corporate Risk Committee. This implies that local trading mandates are relatively small.

The group's Corporate Risk Committee which is headed by the Chief Financial Officer and which includes, among others, representatives from the principal business segments is responsible for defining, developing, and reviewing the group's risk policies. The Chief Financial Officer in co-operation with the Corporate Risk Committee is also responsible for overseeing and developing StatoilHydro's Enterprise-Wide Risk Management and proposing appropriate risk adjusting measures at the corporate level. To help facilitate its role, the Committee meets at least six times per annum and regularly receives risk information relevant for the group from our Corporate Risk Department.

Financial risks

StatoilHydro'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

StatoilHydro operates in the worldwide crude oil, refined products, natural gas, and electricity markets and are exposed to such market risks as 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 focus on achieving the highest risk adjusted returns for the group within the given mandate. Long-term is generally viewed as risks managed at the corporate level and (or) normally having a six months or longer time horizon for significant volumes while short term is generally viewed as risks managed at segment and lower levels according to trading strategies and pre-defined mandates.

The group has established guidelines for entering into contractual arrangements (derivatives) in order to manage our commodity price, foreign currency rate, and interest rate risk. The group uses both financial and commodity-based derivatives to manage the risks in overall earnings and the future value of cash flows.

Commodity price risk

Commodity price risk represents the group's most important short-term market risk and is monitored everyday 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 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

Fluctuations in exchange rates can have significant effects on the group's results. Foreign exchange risk is assessed on a portfolio basis in accordance with approved strategies and mandates and the group uses only well-understood, conventional derivative instruments which include futures and options traded on regulated exchanges, OTC-swaps, -options and forward contracts.

The group's cash inflows are largely influenced by USD while the group's cash outflows are to a large extent, tax and dividend payments in NOK, as well as certain investments, payment of salaries and various other costs payable in NOK. Accordingly, a significant portion of our exposure to foreign currency rates exists with USD versus NOK. StatoilHydro seeks to manage this currency mismatch by issuing or swapping non-current financial debt into USD.

The group further seeks to manage short-term currency mismatches by using derivative instruments both for currency and liquidity management purposes. Typically, the group purchases NOK during the course of a calendar year in order to cover projected NOK payments of Norwegian income taxes and dividends in the first half of a subsequent year. This means, from time to time, the group purchases substantial NOK amounts on a forward basis using derivative instruments.

Interest rate risk
The existence of assets earning and liabilities owing variable rates of interest expose the group to cash flow risk caused by market interest rate fluctuations. The group enters into various types of interest rate contracts in managing interest rate risk. 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. Under interest rate swaps, the group agrees with other parties to exchange, at specified intervals, the difference between interest amounts calculated by reference to an agreed notional principal amount and agreed fixed or floating interest rates.

StatoilHydro principally manages the group's interest rates on the basis that the non-current debt portfolio has floating rate interest payments. The modified duration (the percentage change in value for one percentage point change in yield) expresses the way the group monitors the interest rate risk. Generally, the group's modified duration is to be between 0 and 1.0%. Other strategies can be approved from time to time if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

Liquidity risk
Liquidity risk is the risk that StatoilHydro will not be able to meet obligations when due. The purpose of liquidity and short term liability management is to make certain that the group at all times has sufficient funds available to cover financial obligations.

StatoilHydro's operating cashflows are negatively impacted by declines in oil and gas prices, however, during 2008 the group's overall liquidity position remained strong and the policies for managing liquidity remained unchanged.

StatoilHydro's business activities normally generate, on a monthly basis, a positive cashflow from operations. However, in months when taxes are paid (February, April, June, August, October and December) or annual dividend is paid (typically in May/June) cashflows are typically limited. In the period following tax and dividend payments the amount of liquid assets will often be significantly reduced. A need for short-term funding will then be triggered for a period until the debt is repaid and subsequently followed by a new accumulation of liquid assets.

Short-term financing can be carried out bilaterally through direct borrowing from banks, insurance companies, etc. An alternative is to issue short term debt securities under one of the existing financing programmes or under documentation established ad hoc. These financing programmes are as follows:

- A USD 4 billion US commercial paper programme. This is the most flexible programme used for working capital, including timing issues on corporate tax and dividend payments, as well as for periodic acquisition financing.
- A USD 2 billion committed multi-currency revolving credit facility from international banks, including a USD 500 million swing-line facility. The facility was entered into in 2004, and is available for draw-downs until December 2011. This facility is primarily intended as a "back-up" facility for the US commercial paper programme, and should be regarded as support for the credit rating of this programme.
- Uncommitted credit lines. Short-term financing source occasionally required beyond the other short-term programmes and accumulated cash.

In order to have access to sufficient liquidity at all times, StatoilHydro defines and continuously maintains a minimum liquidity reserve which comprises unused committed external credit facilities, cash and cash equivalents, and current financial investments excluding the current portion of the investment portfolio held by the group's captive insurance subsidiary.

Capital and liability management
As a basic principle, StatoilHydro separates investment decisions from financing decisions. Financing needs arise as a result of the group's general business activity. The main rule is to establish financing at corporate level. Project financing may be applied in cases involving joint ventures with other companies.

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

The group has credit ratings from Moody's and Standard & Poor's and the stated objective is to have a rating at least within the single A category. This rating ensures necessary predictability when it comes to funding access at favourable terms and conditions. The group's current long-term 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. The group intends to keep financial ratios relating to debt at levels consistent with objectives for maintaining the group's long-term credit rating at least within the single A category. In managing the group's capital structure and thus seeking to maintain a credit rating of at least single A, the group partly relies on the use of Standard & Poor's guidelines to test, among others, the key ratios free funds from operations over net debt and the debt ratio.

In order to control the group's refinancing risk, the maturity and redemption profile of non-current debt issued is managed within certain limitations. The limits are expressed as maximum annual mandatory redemptions as a share of StatoilHydro's capital employed.

Liquidity forecasts serve as tools for financial planning. In order to maintain necessary financial flexibility, StatoilHydro has requirements for maximum (forecasted) current debt and minimum (forecasted) liquidity reserve. Issuance of long-term debt is used as a tool for reducing current debt and/or increasing the liquidity reserve. New non-current funding will be initiated if liquidity forecasts reveal non-compliance with given limits, unless further detailed considerations indicate that the non-compliance is likely to be very temporary. In this case, the situation will be further monitored before additional non-current debt is drawn.

For further information on the group's debenture bonds, bank loans, and other debt portfolio profile, see note 20 Non-current financial liabilities.

StatoilHydro's dividend policy includes providing a return to the group's shareholders through cash dividends and share repurchases. The level of cash dividends and share repurchases in any one year can fluctuate depending on the group's assessment of future cashflows, capital expenditure plans, financing requirements, and appropriate financial flexibility. See note 19 Shareholders equity additional information on the group's dividend policy.

Credit risk

Credit risk is the risk that the group's customers or counterparties to financial instruments will cause the group financial loss by failing to honour their obligation. Credit risk arises from credit exposures with customer accounts receivables as well as from 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 2008 and NOK 7.5 billion in 2007), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents. The group manages this exposure through its credit risk management policies and procedures.

The current financial crisis has brought into focus the need for all entities to have robust credit policies with close monitoring of associated risks. Over the years, we have established a clear credit policy which has proven especially valuable during this period of widespread financial pressure. The tools StatoilHydro uses to manage and monitor credit risk have been tested by the continuing crisis and no significant credit losses have materialised for the group during 2008.

Key elements of our credit risk management approach include

- A global credit risk policy
- Credit mandates
- Internal credit rating process
- Credit risk mitigation tools
- Continuously 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 minimum annually with high risk counterparties reviewed more frequently. The internal credit ratings reflect our assessment of the counterparties' credit risk and are similar to rating categories used by well known credit rating agencies, Standard & Poor's and Moody's. Exposure limits are determined based on assigned internal credit ratings combined with other factors, such as expected transaction and industry characteristics, as outlined in our credit policy. The mandate for setting credit limits is regularly reviewed with regard to changes in market conditions.

There are several instruments available to the group to reduce or control credit risk both on an individual counterparty and portfolio level. The main tools used by StatoilHydro are variations of bank and parental guarantees, prepayments and cash collateral. For bank guarantees only investment grade international banks are accepted.

StatoilHydro manages credit risk both on a portfolio and counterparty level. The group has pre-defined limits regarding 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 versus limits on a daily basis. The total credit exposure portfolio of StatoilHydro is well diversified with respect to number and quality of counterparties, industries and geographically. The majority of the group's credit exposure is typically with investment grade counterparties.

The following table contains the fair market value of open non-exchange traded derivative assets split by the group's assessment of the counter-party's credit risk.

	At 31 December	
(in NOK million)	**2008**	**2007**
Counter-party rated:		
Investment grade, rated A or above	21,727	19,647
Other investment grade	7,094	928
Non-investment grade or not rated	761	689

As of 31 December 2008, NOK 10.1 billion is received in cash as collateral to offset a portion of this group credit exposure. See note 24 Current financial liabilities for more information on collateral held.

Consistent with our policies, commodity derivative counter-parties have been assigned credit ratings corresponding to those of their respective parent companies. If the parent company is highly rated, it may not be necessary to obtain a parent company guarantee from such a counter-party.

8.1.29 Financial instruments by category

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 20 - 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	Total carrying amount
31 December 2008							
Assets							
Non-current financial investments	14	-	4,164	-	-	12,301	16,465
Non-current derivative financial instruments	30	-	-	-	2,383	-	2,383
Non-current financial receivables	14	4,914	-	-	-	-	4,914
Current trade and other receivables	16	69,931	-	-	-	-	69,931
Current derivative financial instruments	30	-	-	27,436	69	-	27,505
Current financial investments	17	15	-	7,874	-	1,858	9,747
Cash and cash equivalents	18	18,638	-	-	-	-	18,638
Total		93,498	4,164	35,310	2,452	14,159	149,583

(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	Total carrying amount
31 December 2007							
Assets							
Non-current financial investments	14	-	3,291	-	-	11,975	15,266
Non-current derivative financial instruments	30	-	-	-	609	-	609
Non-current financial receivables	14	3,515	-	-	-	-	3,515
Current trade and other receivables	16	69,378	-	-	-	-	69,378
Current derivative financial instruments	30	-	-	21,051	42	-	21,093
Current financial investments	17	-	-	3,359	-	-	3,359
Cash and cash equivalents	18	18,264	-	-	-	-	18,264
Total		91,157	3,291	24,410	651	11,975	131,484

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Total carrying amount
31 December 2008					
Liabilities					
Non-current financial liabilities	20	52,065	2,541	-	54,606
Current trade and other payables	23	61,200	-	-	61,200
Current financial liabilities	24	20,695	-	-	20,695
Current derivative financial instruments	30	-	-	20,752	20,752
Total		133,960	2,541	20,752	157,253

(in NOK million)	Note	Amortised cost	Hedge accounting	Fair value through profit or loss	Total carrying amount
31 December 2007					
Liabilities					
Non-current financial liabilities	20	43,649	724	1	44,374
Current trade and other payables	23	64,624	-	-	64,624
Current financial liabilities	24	6,166	-	-	6,166
Current derivative financial instruments	30	-	-	7,632	7,632
Total		114,439	724	7,633	122,796

Included in Current trade and other payables are provisions for certain claims and litigations in accordance with IAS 37 which are further described in note 26 Other commitments and contingencies.

The following tables include amounts from the Consolidated statements of income related to financial instruments. Excluded from Net financial items is accretion expense on our asset retirement obligations of NOK 2,107, NOK 2,099 and NOK 1,304 million for the years ended 2008, 2007 and 2006, respectively. See note 8, Financial items, for additional information on the Net financial items.

	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	Total
For the year ended 31 December 2008:							
Operating income	19,917	-	-	-	-	-	19,917
Net financial items							
Net foreign exchange gains (losses)	(23,061)	-	(1,256)	3,900	(12,145)	-	(32,563)
Interest income and other financial items	8,927	-	(213)	3,461	-	31	12,207
Interest and other finance expenses	6,725	(27)	(1)	-	(2,599)	-	4,098
Total	12,508	(27)	(1,470)	7,361	(14,744)	31	3,659

	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	Total
For the year ended 31 December 2007:							
Operating income	(2,043)	-	-	-	-	129	(1,914)
Net financial items							
Net foreign exchange gains (losses)	8,610	-	596	(8,630)	9,467	-	10,043
Interest income and other financial items	(82)	-	139	1,820	-	428	2,305
Interest and other finance expenses	361	9	(40)	-	(972)	-	(642)
Total	6,846	9	695	(6,810)	8,495	557	9,792

	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	Total
For the year ended 31 December 2006:							
Operating income	7,303	-	-	-	-	-	7,303
Net financial items							
Net foreign exchange gains (losses)	3,947	-	112	(1,067)	1,465	-	4,457
Interest income and other financial items	780	-	965	1,751	(79)	258	3,675
Interest and other finance expenses	(1,352)	(7)	(27)	-	(349)	(21)	(1,756)
Total	10,678	(7)	1,050	684	1,037	237	13,679

8.1.30 Financial instruments and hedging

Fair value hedges

Fair value hedges are hedges of StatoilHydro's exposure to changes in the fair value of a recognised asset and liability. StatoilHydro has designated certain interest rate swaps as fair value hedge to hedge against changes in the fair value, due to changes in the interest rates, of certain parts of the group's financial liabilities. The net loss recognised in earnings in Income before tax during the year for ineffectiveness of fair value hedges was insignificant.

The fair value of the hedging instruments and the hedged item subject to hedge accounting are presented below together with related annual gains and losses.

(in NOK million)	Fair value	Gains /(losses)
At 31 December 2008		
Hedging instruments	2,452	2,036
Hedged item	(2,541)	(2,063)
At 31 December 2007		
Hedging instruments	651	221
Hedged item	(724)	(212)
At 31 December 2006		
Hedging instruments	430	(459)
Hedged item	(512)	452

Fair value of derivative financial instruments

The group recognises all derivative financial instruments in the balance sheet at fair value. Changes in the fair value of these derivatives are included in the Consolidated statements of income either in revenue or in financial items. For more information about the methodology and assumption used when calculating the fair value of our financial instruments see note 2 Significant accounting policies.

The following table contains the estimated fair values and net carrying amounts of derivative financial instruments including certain derivative commodity contracts. Of the total ending balance at 31 December 2008 NOK 9.7 billion relates to certain earn-out agreements recognised as derivative financial instruments in accordance with IAS 39. At the end of 2007 the estimated fair value of these agreements were NOK 9.6 billion.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
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
Gas and Electricity	3,267	(3,239)	28
At 31 December 2007			
Debt-related instruments	4,676	(125)	4,551
Non-debt-related instruments	1,802	(163)	1,639
Crude Oil and Refined products	11,115	(2,533)	8,582
Gas and Electricity	4,219	(4,921)	(702)

Where an active market exists, derivative financial instruments are valued on the the basis of quoted information from the active market. The following table summarises the basis for the group's fair value estimation and the maturity of our derivative financial instruments.

(in NOK million)	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total fair value
At 31 December 2008					
Fair value based on prices quoted in an active market	55	(180)	(20)	0	(145)
Fair value based on price inputs from observable market transactions	(11,330)	4,287	2,229	8,297	3,483
Fair value based on inputs from other sources	348	485	729	4,236	5,798
At 31 December 2007					
Fair value based on prices quoted in an active market	175	1,731	178	2,108	4,192
Fair value based on price inputs from observable market transactions	5	7	0	0	12
Fair value based on inputs from other sources	13	(1)	(1)	9,854	9,865

The first level in the above table, Fair value based on prices quoted in an active market, refers to values generated for standardised products actively traded where our values is calculated based on observable prices on equal product. This category will in most cases only be relevant for exchange traded contracts.

Fair value based on price inputs from observable market transactions is used for fair values that are calculated for our non-standardised contracts based on price inputs that are from observable market transaction. This will typically be when we use forward prices on crude oil, natural gas, interest rates, and foreign exchange rates as inputs into our valuation models.

Fair value based on input from other sources 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.

Even though the major part of the fair value from certain earn-out agreements and embedded derivative contracts are calculated with price inputs from observable market transaction they have been classified in the third category in the above table due to part of the value being from internal generated assumptions. Another reasonable assumption to be used when calculating the fair value of these contracts might be to extrapolate the last observed forward prices. By extrapolating the forward curves with inflation the fair value of the contracts included will decrease by approximately NOK 1.0 billion. This decreased change in fair value would be recognised in the Consolidated statements of income.

There are significant measurement risks associated with estimating the fair value of financial instruments that are not traded in active markets. While these are StatoilHydro's best estimates of fair value, other assumptions may be made by other parties for instance with respect to future commodity prices, exchange rates and interest rates. The sensitivity of the fair value of all commodity-based contracts on changes in commodity prices is illustrated in the sensitivity table below. Changes in the fair value of commodity-based financial instruments due to different assumptions made on future exchange rates and interest rates are deemed immaterial.

Market risk sensitivities

Commodity price risk

The table below contains the fair value and related commodity price risk sensitivity of our commodity based derivatives contracts, as accounted for under IAS 39. For further information related to the type of commodity risks and how the group manages these risks see note 28 Financial risk management.

Substantially all of these fair value assets and liabilities are 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. Included in the fair values and basis for sensitivity figures are immaterial derivative positions held for speculative trading purposes.

Price risk sensitivities by end of 2008 have been calculated by assuming a 50% change in all commodity prices. Compared to the sensitivity calculated by end of 2007 and 2006 the group's assessment of what are reasonable possible changes in the commodity prices for the coming year have been changed due to the changes taking place in the markets where we operate. By end of 2007 and 2006 this sensitivity was calculated by assuming a 10% change in all commodity prices.

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

(in NOK million)	Fair value asset	Fair value liability	-50% sensitivity	50% sensitivity
At 31 December 2008				
Crude Oil and Refined Products	13,136	(2,491)	(4,124)	4,440
Natural Gas and Electricity	3,267	(3,239)	3,447	(3,431)
			-10% sensitivity	10% sensitivity
At 31 December 2007				
Crude Oil and Refined Products	11,115	(2,533)	(651)	652
Natural Gas and Electricity	4,219	(4,921)	1,530	(1,522)
At 31 December 2006				
Crude Oil and Refined Products	7,593	(797)	(466)	410
Natural Gas and Electricity	7,501	(4,432)	1,742	(1,671)

As part of the tools to monitor and manage risk, the group uses value at risk (VaR) method for certain parts of its commodity trading activity within the Natural Gas and Manufacturing and Marketing segment.

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.

Natural Gas mainly measures its market risk exposure using a variance/covariance VaR model. Furthermore a 95% confidence interval and a one day holding period is applied. The variance/covariance model 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 model 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 model calculates the VaR as a function of standard deviation per instrument in the portfolio and the correlation between the instruments while the historical simulation method is based on deriving daily percentage market price and volatility changes for all significant products in the 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.

Within the 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 the group's balance sheet. Within Natural Gas embedded derivatives as well as certain physical forward contracts recognised as derivative financial instrument that is not held as part of a trading position is not included in the portfolio subject to VaR limits.

The calculated VaR numbers for 2008 and a summary of the assumptions used are presented in the following table.

(in NOK million)	High	Low	Average
Crude Oil and Refined Products	143	28	79
Natural Gas and Electricity	392	88	216

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 and currency risk.
Interest and currency risks constitute significant financial risks for the StatoilHydro group. Total exposure is managed at a portfolio level in accordance with approved strategies and mandates on a regular basis.

The following currency risk sensitivities by end of 2008 have been calculated by assuming a 20% change foreign exchange rates. Compared to the sensitivity calculated by end of 2007 and 2006 the group's assessment of what are reasonable possible changes in foreign currencies we are exposed to for the coming year have been changed due to the changes taken place in the world financial markets. By end for 2007 and 2006 a 10% change was assumed in the calculation. Included in currency risk calculations are financial assets, financial liabilities and financial derivatives exclusive commodity derivatives. For the interest rate risk sensitivity a one percentage point change in the interest rates have been used in the calculation which is the same as by end of 2007 and 2006. The estimated gains and losses that will impact our income statement are presented in the following table.

(in NOK million)	Gains	Losses
At 31 December 2008		
Currency risk (20% sensitivity)	28,116	(28,116)
Interest rate risk (1 percentage point sensitivity)	3,395	(3,395)
At 31 December 2007		
Currency risk (10% sensitivity)	10,387	(10,387)
Interest rate risk (1 percentage point sensitivity)	2,714	(2,714)
At 31 December 2006		
Currency risk (10% sensitivity)	7,620	(7,620)
Interest rate risk (1 percentage point sensitivity)	2,354	(2,354)

For further information related to the interest and currency risks and how the group manages these risks see note 28 Financial risk management.

Equity risk
Listed equity securities, consisting mainly of the portfolio held by the group's captive insurance company, are recorded at fair value and have exposure to price risk. The fair value of listed equity securities is based on quoted market prices. In addition to the portfolio held by the group's captive insurance company, the group also has some other non-listed equity securities classified as Available for sale investments in accordance with IAS 39.

For more information about the fair values recognised in the balance sheet, the assumption used when calculating the fair value and the price risk sensitivities of the equity securities see note 14 Non-current financial assets.

Liquidity risk
The liquidity risk in terms of crude oil and refined products derivative contracts is usually less than one year. The term of natural gas forwards is usually three years or less. In the table below the maturity profile for the group's financial liability related to exchange traded and non-exchange traded commodity based derivatives together with financial derivatives is presented. The maturity profile is based on the underlying delivery period of the contracts included in the portfolio. For further information on management of the liquidity risk, see note 28 - Financial risk management.

(in NOK million)	2008	2007
Less than 1 year	(18,194)	(5,279)
1 - 3 years	(1,551)	(2,094)
4 - 5 years	(276)	(113)
After 5 years	(698)	(147)
Derivative financial instruments	(20,719)	(7,633)

8.1.31 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 StatoilHydro'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, StatoilHydro 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 StatoilHydro 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 StatoilHydro 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 StatoilHydro as "Merger related adjustments", see note 19 Shareholders equity.

StatoilHydro, 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 StatoilHydro ASA above the age of 58 years (contingent upon certain conditions).

Below is a table showing the effects of the merger on the Statement of Income for the year ended 31 December 2006. The column "Hydro Petroleum" includes the IFRS financial information derived from the audited carve-out combined financial statements of Hydro Petroleum. The column "Former Statoil group" is derived from the IFRS transition document of Statoil ASA. The column " Merger adjustments and other eliminations" includes StatoilHydro's managements consolidation entries and adjustments to a) conform the Hydro Petroleum IFRS financial information to the accounting policies of StatoilHydro and b) eliminate internal transactions between the merged companies.

Condensed Statements of Income

	For the year ended 31 December 2006			
(in NOK million)	Hydro Petroleum	Former Statoil group	Merger adjustments and other eliminations	StatoilHydro group
Total revenues and other income	97,910	433,966	(10,394)	521,482
Total operating expenses	(51,192)	(315,009)	10,883	(355,318)
Net financial items	563	3,797	712	5,072
Income tax	(36,188)	(81,889)	(1,312)	(119,389)
Net income	11,093	40,865	(111)	51,847

8.1.32 Subsequent events

Effective 1 January 2009, StatoilHydro completed an internal group reorganisation in which the parts of the Exploration and Production Norway segment activities and assets previously owned by StatoilHydro ASA, excluding employees employed by StatoilHydro ASA, were transferred to the wholly owned subsidiary StatoilHydro Petroleum AS. Some parts of the Natural Gas segment activities and assets, but no employees, were also transferred. Following these reorganisations the operations of StatoilHydro ASA is no longer subject to the special petroleum tax on the Norwegian Continental Shelf. As a consequence, the tax assets related to pension liabilities in StatoilHydro ASA have effective 31 December 2008 been recognised at 28%, which is the tax rate expected to be in effect at the realisation date. Previously the estimated tax rate was 56%, based on assumed amounts expected to be realised under the petroleum tax regime and the general tax regime, respectively. The effect is a reduction of the deferred tax assets related to pensions and a corresponding reduction to retained earnings by NOK 5.4 billion as of 31 December 2008.

The 1 January 2009 internal group reorganisation has also resulted in a change of functional currency from NOK to USD in StatoiHydro ASA effective from the same date and with prospective effect. The functional currency of StatoilHydro Petroleum AS has not changed and remains NOK. The change of functional currency in StatoilHydro ASA has no impact on the consolidated financial statements for 2008. The presentation currency for the StatoiHydro group will remain NOK.

On 4 March 2009 StatoilHydro ASA issued a GBP 800 million bond with a 22 year tenure, a EUR 1.2 billion bond with a 12 year tenure and a EUR 1.3 billion bond with a six year tenure. All three bonds were fully subscribed. The bonds are issued under StatoilHydro ASA's Euro Medium Term Note Programme and will be listed on London Stock Exchange. The bonds have been guaranteed by StatoilHydro Petroleum AS.

8.1.33 Condensed consolidating financial information related to guaranteed debt securities issued by parent company

At 31 December 2008, StatoilHydro's oil and gas activities and net assets on the Norwegian Continental Shelf (NCS) were owned by StatoilHydro ASA and by StatoilHydro Petroleum AS. With effect from 1 January 2009, StatoilHydro ASA has transferred the ownership of its NCS net assets to StatoilHydro Petroleum AS, a 100% owned operating subsidiary. Following the transfer, all NCS net assets are owned by StatoilHydro Petroleum AS. Effective from the same date, StatoilHydro Petroleum AS became the co-obligor of certain existing debt securities of StatoilHydro ASA and guarantor of certain other debt securities of StatoilHydro ASA and irrevocably assume and agree to perform the payment and covenant obligations for the related debt securities. StatoilHydro ASA may issue future debt securities from time to time pursuant to registration statements filed with the SEC for which StatoilHydro Petroleum AS is the co-obligor or guarantor of such debt securities.

The following financial information on a condensed consolidating basis provides investors with financial information about StatoilHydro ASA, StatoilHydro Petroleum AS, as co-obligor, and all other subsidiaries as required by SEC Rule 3-10 of Regulation S-X as of 1 January 2009. The transfer of ownership of the NCS net assets from StatoilHydro ASA to StatoilHydro Petroleum AS was a common control transaction. StatoilHydro ASA accounts for common control transactions by recognising the carrying amounts of assets and liabilities transferred and restating the financial statements for all periods presented to reflect the transaction as if it at occurred at the beginning of the periods presented. The condensed consolidating information presented below reflects the transfer of NCS assets to the Co-obligor for all periods presented. The condensed consolidating information is prepared in accordance with the group's IFRS accounting policies as described in note 2 Significant accounting policies except that investments in subsidiaries are accounted for using the equity method of accounting as required by Rule 3-10. The functional currency for StatoilHydro ASA figures presented is NOK.

The following is condensed consolidated financial information as of 31 December, 2008 and 2007 and for the years ended 31 December 2008, 2007, and 2006.

CONSOLIDATED STATEMENTS OF INCOME

2008 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	389,618	249,432	242,995	(230,068)	651,977
Net income (loss) from equity associated companies	57,648	4,408	1,105	(61,878)	1,283
Other income	521	20	2,572	(353)	2,760
Total revenues and other income	447,787	253,860	246,672	(292,299)	656,020
OPERATING EXPENSES					
Purchases [net of inventory variation]	(360,897)	(4,045)	(181,803)	217,563	(329,182)
Operating expenses	(13,718)	(37,081)	(14,293)	5,743	(59,349)
Selling, general and administrative expenses	(11,500)	36	(8,789)	9,289	(10,964)
Depreciation, amortisation and impairment losses	(693)	(26,215)	(16,088)	0	(42,996)
Exploration expenses	(551)	(5,540)	(8,606)	0	(14,697)
Total operating expenses	(387,359)	(72,845)	(229,579)	232,595	(457,188)
Net operating income	60,428	181,015	17,093	(59,704)	198,832
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	(38,112)	2,154	3,395	0	(32,563)
Interest income and other financial items	10,449	1,895	10,740	(10,877)	12,207
Interest and other net finance expenses	1,025	(4,705)	(5,206)	10,877	1,991
Net financial items	(26,638)	(656)	8,929	0	(18,365)
Income before tax	33,790	180,359	26,022	(59,704)	180,467
Income tax	9,476	(132,310)	(13,612)	(751)	(137,197)
Net income	43,266	48,049	12,410	(60,455)	43,270

CONSOLIDATED STATEMENTS OF INCOME

2007 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	272,614	200,680	197,452	(149,081)	521,665
Net income (loss) from equity associated companies	38,221	847	667	(39,126)	609
Other income	2	165	356	0	523
Total revenues and other income	310,837	201,692	198,475	(188,207)	522,797
OPERATING EXPENSES					
Purchases [net of inventory variation]	(257,608)	(3,739)	(135,677)	136,628	(260,396)
Operating expenses	(10,149)	(42,166)	(12,604)	4,601	(60,318)
Selling, general and administrative expenses	(9,656)	(1,534)	(9,422)	6,438	(14,174)
Depreciation, amortisation and impairment losses	(631)	(24,747)	(13,994)	0	(39,372)
Exploration expenses	(713)	(4,074)	(6,546)	0	(11,333)
Total operating expenses	(278,757)	(76,260)	(178,243)	147,667	(385,593)
Net operating income	32,080	125,432	20,232	(40,540)	137,204
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	15,979	(639)	(5,297)	0	10,043
Interest income and other financial items	4,134	241	3,875	(5,945)	2,305
Interest and other net finance expenses	(5,128)	(2,208)	(1,350)	5,945	(2,741)
Net financial items	14,985	(2,606)	(2,772)	0	9,607
Income before tax	47,065	122,826	17,460	(40,540)	146,811
Income tax	(2,971)	(92,897)	(6,730)	428	(102,170)
Net income	44,094	29,929	10,730	(40,112)	44,641

CONSOLIDATED STATEMENTS OF INCOME

2006 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
REVENUES AND OTHER INCOME					
Revenues	244,497	211,007	182,013	(118,557)	518,960
Net income (loss) from equity associated companies	52,196	(359)	208	(51,366)	679
Other income	9	657	1,177	0	1,843
Total revenues and other income	296,702	211,305	183,398	(169,923)	521,482
OPERATING EXPENSES					
Purchases [net of inventory variation]	(227,983)	(2,155)	(127,118)	107,663	(249,593)
Operating expenses	(10,936)	(30,183)	(10,245)	6,563	(44,801)
Selling, general and administrative expenses	(5,141)	(950)	(8,724)	3,991	(10,824)
Depreciation, amortisation and impairment losses	(345)	(22,443)	(16,662)	0	(39,450)
Exploration expenses	(489)	(3,780)	(6,381)	0	(10,650)
Total operating expenses	(244,894)	(59,511)	(169,130)	118,217	(355,318)
Net operating income	51,808	151,794	14,268	(51,706)	166,164
FINANCIAL ITEMS					
Net foreign exchange gains (losses)	5,665	555	(1,763)	0	4,457
Interest income and other financial items	1,137	461	5,021	(2,944)	3,675
Interest and other net finance expenses	(6,147)	(1,022)	1,165	2,944	(3,060)
Net financial items	655	(6)	4,423	0	5,072
Income before tax	52,463	151,788	18,691	(51,706)	171,236
Income tax	(1,345)	(115,362)	(2,783)	101	(119,389)
Net income	51,118	36,426	15,908	(51,605)	51,847

CONSOLIDATED BALANCE SHEETS

At 31 December 2008 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
Non-current assets					
Property, plant and equipment	5,698	187,739	136,404	0	329,841
Intangible assets	7	6,888	59,141	0	66,036
Shares in subsidiaries	314,779	69,586	4,750	(389,115)	0
Equity accounted investments	845	1,070	11,078	(353)	12,640
Deferred tax assets	7,187	0	1,302	(7,187)	1,302
Pension assets	0	0	30	0	30
Financial investments	12	7	16,446	0	16,465
Derivative financial instruments	2,383	0	0	0	2,383
Financial receivables	343	539	4,032	0	4,914
Financial receivables from subsidiaries	44,148	56	26,332	(70,536)	0
Total non-current assets	375,402	265,885	259,515	(467,191)	433,611
Current assets					
Inventories	5,884	942	9,858	(1,533)	15,151
Trade and other receivables	36,394	12,918	20,619	0	69,931
Current tax receivables	2,959	881	0	0	3,840
Receivables from subsidiaries	10,740	39,059	97,912	(147,711)	0
Derivative financial instruments	14,298	9,751	3,456	0	27,505
Financial investments	2,616	0	7,131	0	9,747
Cash and cash equivalents	6,272	0	12,366	0	18,638
Total current assets	79,163	63,551	151,342	(149,244)	144,812
TOTAL ASSETS	454,565	329,436	410,857	(616,435)	578,423

CONSOLIDATED BALANCE SHEETS

At 31 December 2008 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
Equity					
Paid in Capital and Retained Earnings	196,825	104,827	265,445	(370,272)	196,825
Other reserves	17,254	2,738	17,254	(19,992)	17,254
StatoilHydro shareholders' equity	214,079	107,565	282,699	(390,264)	214,079
Minority interest	0	0	1,976	0	1,976
Total equity	214,079	107,565	284,675	(390,264)	216,055
Non-current liabilities					
Financial liabilities	49,858	767	3,981	0	54,606
Non-current liabilities to subsidiaries	37	42,623	27,897	(70,557)	0
Deferred tax liabilities	0	69,722	5,948	(7,526)	68,144
Pension liabilities	20,649	4,312	577	0	25,538
Other provisions	1,233	34,838	18,686	(398)	54,359
Total non-current liabilities	71,777	152,262	57,089	(78,481)	202,647
Current liabilities					
Trade and other payables	22,992	16,966	21,242	0	61,200
Income taxes payable	1,896	50,746	4,432	0	57,074
Financial liabilities	18,784	255	1,656	0	20,695
Derivative financial instruments	18,814	20	1,918	0	20,752
Current liabilities to subsidiaries	106,223	1,622	39,845	(147,690)	0
Total current liabilities	168,709	69,609	69,093	(147,690)	159,721
Total liabilities	240,486	221,871	126,182	(226,171)	362,368
TOTAL EQUITY AND LIABILITIES	454,565	329,436	410,857	(616,435)	578,423

CONSOLIDATED BALANCE SHEETS

At 31 December 2007 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
ASSETS					
Non-current assets					
Property, plant and equipment	5,317	179,446	93,589	0	278,352
Intangible assets	8	4,946	39,896	0	44,850
Shares in subsidiaries	201,251	53,208	2,811	(257,270)	0
Equity accounted investments	952	1,470	5,999	0	8,421
Deferred tax assets	0	0	3,610	(2,817)	793
Pension assets	1,561	0	61	0	1,622
Financial investments	13	15	15,238	0	15,266
Derivative financial instruments	609	0	0	0	609
Financial receivables	214	337	2,964	0	3,515
Financial receivables from subsidiaries	46,774	31	52	(46,857)	0
Total non-current assets	256,699	239,453	164,220	(306,944)	353,428
Current assets					
Inventories	7,296	1,526	12,536	(3,662)	17,696
Trade and other receivables	38,939	9,587	20,852	0	69,378
Receivables from subsidiaries	10,271	10,999	48,941	(70,211)	0
Derivative financial instruments	7,327	9,704	4,062	0	21,093
Financial investments	155	0	3,204	0	3,359
Cash and cash equivalents	21	(7)	18,250	0	18,264
Total current assets	64,009	31,809	107,845	(73,873)	129,790
TOTAL ASSETS	320,708	271,262	272,065	(380,817)	483,218

CONSOLIDATED BALANCE SHEETS

At 31 December 2007 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
EQUITY AND LIABILITIES					
Equity					
Paid in Capital and Retained Earnings	189,886	76,111	200,826	(276,937)	189,886
Other reserves	(12,611)	(4,484)	(12,611)	17,095	(12,611)
StatoilHydro shareholders' equity	177,275	71,627	188,215	(259,842)	177,275
Minority interest	0	0	1,792	0	1,792
Total equity	177,275	71,627	190,007	(259,842)	179,067
Non-current liabilities					
Financial liabilities	35,425	4,615	4,334	0	44,374
Non-current liabilities to subsidiaries	27	42,670	4,162	(46,859)	0
Deferred tax liabilities	468	63,683	7,233	(3,907)	67,477
Pension liabilities	18,384	0	708	0	19,092
Other provisions	2,001	32,941	8,903	0	43,845
Total non-current liabilities	56,305	143,909	25,340	(50,766)	174,788
Current liabilities					
Trade and other payables	33,668	13,701	17,255	0	64,624
Income taxes payable	6,261	40,542	4,138	0	50,941
Financial liabilities	4,718	13	1,435	0	6,166
Derivative financial instruments	3,901	531	3,200	0	7,632
Current liabilities to subsidiaries	38,580	939	30,690	(70,209)	0
Total current liabilities	87,128	55,726	56,718	(70,209)	129,363
Total liabilities	143,433	199,635	82,058	(120,975)	304,151
TOTAL EQUITY AND LIABILITIES	320,708	271,262	272,065	(380,817)	483,218

CASH FLOW STATEMENT

At 31 December 2008 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	(11,182)	75,887	44,181	(6,353)	102,533
Cash flows used in investing activities	(70,188)	(52,003)	(36,492)	72,846	(85,837)
Cash flows used in financing activities	87,618	(23,879)	(14,275)	(66,493)	(17,029)
Net increase (decrease) in cash and cash equivalents	6,248	5	(6,586)	0	(333)
Effect of exchange rate changes on cash and cash equivalents	0	(5)	712	0	707
Cash and cash equivalents at the beginning of the period	23	0	18,241	0	18,264
Cash and cash equivalents at the end of the period	6,271	0	12,367	0	18,638

CASH FLOW STATEMENT

At 31 December 2007 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	15,343	56,394	34,902	(12,713)	93,926
Cash flows used in investing activities	(29,400)	(46,679)	(27,910)	28,877	(75,112)
Cash flows used in financing activities	14,084	(9,728)	3,900	(16,164)	(7,908)
Net increase (decrease) in cash and cash equivalents	27	(13)	10,892	0	10,906
Effect of exchange rate changes on cash and cash equivalents	0	0	(160)	0	(160)
Cash and cash equivalents at the beginning of the period	(4)	8	7,514	0	7,518
Cash and cash equivalents at the end of the period	23	(5)	18,246	0	18,264

CASH FLOW STATEMENT

At 31 December 2006 (in NOK million)	StatoilHydro ASA	StatoilHydro Petroleum AS	Other subsidiaries	Consolidation adjustments	Group
Cash flows provided by operating activities	1,724	72,066	22,198	(7,395)	88,593
Cash flows used in investing activities	(6,491)	(35,582)	(20,726)	5,624	(57,175)
Cash flows used in financing activities	4,580	(36,496)	(1,233)	1,771	(31,378)
Net increase (decrease) in cash and cash equivalents	(187)	(12)	239	0	40
Effect of exchange rate changes on cash and cash equivalents	0	0	42	0	42
Cash and cash equivalents at the beginning of the period	183	20	7,233	0	7,436
Cash and cash equivalents at the end of the period	(4)	8	7,514	0	7,518

As of 1 January 2009, StatoilHydro Petroleum AS has become a co-obligor of the following securities of StatoilHydro ASA: USD 300,000,000 aggregate principal amount 6.36% Notes due 2009, USD 350,000,000 aggregate principal amount 9.00% Debentures due 2012, USD 99,522,000 aggregate principal amount 9.125% Debentures due 2014, USD 300,000,000 aggregate principal amount 7.50% Debentures due 2016, USD 250,000,000 aggregate principal amount 6.70% Debentures due 2018, USD 300,000,000 aggregate principal amount 7.75% Debentures due 2023, USD 250,000,000 aggregate principal amount 7.15% Debentures due 2025, USD 480,512,000 aggregate principal amount 7.25% Debentures due 2027, USD 250,000,000 aggregate principal amount 6.80% Debentures due 2028 and USD 275,000,000 aggregate principal amount 7.15% Debentures due 2029, each issued under an Indenture dated as of April 15, 1992. As amended; USD 500,000,000 aggregate principal amount 7.25% Debentures due 2027 issued under an Indenture dated as of July 8, 1994. As amended; the USD 500,000,000 aggregate principal amount 5.125% Notes due 2014, USD 250,000,000 aggregate principal amount 7.375% Debentures due 2016 and USD 500,000,000 aggregate principal amount 6.50% Debentures due 2028, issued under the Fiscal and Paying Agency Agreements dated as of 27 April 2004, 7 May 1996, and 14 December 1998, respectively.

StatoilHydro Petroleum AS will be a guarantor of the following securities of StatoilHydro ASA: the USD 250,000,000 aggregate principal amount 7.875% notes due 2022 and USD 100,000,000 aggregate principal amount 6.50% notes due 2023, each issued under the Agency Agreement dated as of July 7, 1988. As amended; the GBP 225,000,000 aggregate principal amount 6.50% Notes due 2021 and EUR 400,000,000 aggregate principal amount 6.25% Notes due 2010 issued under the Trust Deed dated as of January 22, 1999; the EUR 20,000,000 aggregate principal amount Step-up Notes due 2029, GBP 225,000,000 aggregate principal amount 6.125% notes due 2028, JPY 5,000,000,000 aggregate principal amount Fixed Rate Notes due 2012, EUR 500,000,000 aggregate principal amount 5.125% notes due 2011, and USD 375,000,000 aggregate principal amount 5.75%. Notes due 2009, each issued under StatoilHydro ASA's EMTN program; and the CHF 200,000,000 aggregate principal amount 4% Bonds 1999-2009.

StatoilHydro Petroleum AS also became the guarantor or co-obligor as of 1 January 2009 of certain non registered debt securities sold outside the US. The company may also issue future non registered debt securities from time to time that are offered to non US investors for which StatoilHydro Petroleum AS is the guarantor or co-obligor of such debt securities.

StatoilHydro ASA has become a co-obligor under StatoilHydro Petroleum AS' USD 100,000,000 aggregate principal amount 9.125% Debentures due 2014 issued under an Indenture dated as of July 8, 1994, as amended.

8.1.34 Supplementary oil and gas information (UNAUDITED)

In accordance with Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" (FAS 69), StatoilHydro is making certain supplemental disclosures about oil and gas exploration and production operations. While this information is developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgment involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of StatoilHydro or its expected future results.

Certain reclassifications have been made to prior periods' figures to be consistent with the current period's classifications.

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
StatoilHydro'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.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

1. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
2. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
3. Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Over time, undeveloped reserves will be reclassified to proved developed reserves as new wells are drilled, existing wells are recompleted or facilities to produce from existing wells and planned wells comes in operation.

Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

From the Norwegian Continental Shelf (NCS) StatoilHydro 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, StatoilHydro will deliver gas to customers in accordance with various types of sales contracts. In order to fulfil the commitments, StatoilHydro will utilise a field supply schedule which provides the highest possible total value for the joint portfolio of oil and gas between StatoilHydro and SDFI.

As of 31 December 2008, the StatoilHydro / SDFI arrangement amounted to a total of 31.9 tcf in total expected gas commitments on the NSC. The principles for booking of proved reserves are limited to contracted gas sales and gas with access to a market.

The majority of StatoilHydro's gas volumes are sold under long term contracts with Take or Pay clauses. For each individual year, StatoilHydro and SDFI express their delivery commitments as the sum of the Annual Contract Quantity (ACQ). In the contract years 2008 to 2011, the joint ACQ for the respective years are; 2.66, 2.59, 2.62, and 2.56 tcf. The majority of delivery commitments will be fulfilled by expected production of proved reserves from fields were StatoilHydro and/or SDFI participates, while potential shortfalls will be covered by sourcing existing gas markets.

StatoilHydro experiences a situation with reduced supply of LNG due to production problems at the Snøhvit LNG liquefaction plant in Norway. Actions and efforts have been carried out in order to mitigate the effect of the reduced supply. The production problems contributed to a shortfall of approximately 2.0% of StatoilHydro's delivery commitments throughout the year 2008. The effect of the production problems may also result in some shortfalls in LNG supply for 2009.

StatoilHydro 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 StatoilHydro 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 StatoilHydro. 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 StatoilHydro general meeting. Due to this uncertainty and the Norwegian State's estimate of proved reserves not being available to StatoilHydro, it is not possible to determine the total quantities to be purchased by StatoilHydro under the owner's instruction from properties in which it participates in the operations.

In 2002, StatoilHydro entered into a buy-back contract in Iran. StatoilHydro 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 StatoilHydro 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 table.

Rule 4-10 of Regulation S-X requires that the appraisal of reserves is based on the economic environment and operating conditions existing at year end. Reserves at year-end 2008 have been determined based on the Brent price on 31 December 2008 ($36.55/bbl). The reduction in oil price from year-end 2007 (Brent blend price of $96.02/bbl) to year-end 2008 has lowered the profitable oil and gas to be recovered from the accumulations while StatoilHydro's proved oil and gas reserves under PSAs and similar contracts have as a result increased. These changes are included in the revisions category in the table below.

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

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

The acquisition of a 32.5 % interest in the Chesapeake's Marcellus shale gas acreage in the Appalachia region of the northeastern USA was completed in November 2008. Few wells are currently in production and the nature of shale gas deposits limits the reserves that can currently be booked as proved. Proved gas reserves at year-end 2008 related to this ownership is immaterial compared to StatoilHydro's total proved reserves and hence not included.

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

The following table reflects the estimated proved reserves of oil and gas at 31 December 2005 to 2008, 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
At 31 December 2005	1,835	779	2,614	19,595	1,392	20,986	5,316	1,025	6,341
Of which:									
Proved developed reserves	1,363	295	1,659	13,899	208	14,107	3,833	332	4,165
Proved reserves under PSA and buy-back agreements	-	433	433	-	973	973	-	606	606
Production from PSA and buy-back agreements	-	46	46	-	83	83	-	61	61
Revisions and improved recovery	122	37	159	529	250	780	219	81	300
Extensions and discoveries	26	12	38	256	9	265	72	13	86
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	-	(2)	(3)	-	-	-	-	(2)	(3)
Production	(315)	(70)	(385)	(1,250)	(84)	(1,335)	(539)	(85)	(624)
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	-	441	441	-	1,169	1,169	-	649	649
Production from PSA and buy-back agreements	-	47	47	-	56	56	-	57	57
Revisions and improved recovery	197	16	214	598	(27)	571	311	14	325
Extensions and discoveries	38	105	143	405	-	405	110	105	215
Purchase of reserves-in-place	-	-	-	-	-	-	-	-	-
Sales of reserves-in-place	-	-	-	-	-	-	-	-	-
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	-	387	387	-	977	977	-	561	561
Production from PSA and buy-back agreements	-	67	67	-	80	80	-	82	82

	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
Revisions and improved recovery	81	95	177	7	141	148	83	120	203
Extensions and discoveries	12	-	12	29	-	29	17	-	17
Purchase of reserves-in-place	-	69	69	-	-	-	-	69	69
Sales of reserves-in-place	-	(3)	(3)	-	(43)	(43)	-	(10)	(10)
Transfer to affiliated company *	-	(191)	(191)	-	-	-	-	(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	-	433	433	-	1,106	1,106	-	630	630
Production from PSA and buy-back agreements	-	66	66	-	88	88	-	82	82
Reserves in affiliates									
Remaining reserves after transfer*	-	123	123	-	-	-	-	123	123
Revisions and improved recovery	-	11	11	-	-	-	-	11	11
Production	-	(6)	(6)	-	-	-	-	(6)	(6)
At 31 December 2008	-	127	127	-	-	-	-	127	127
Total Proved Reserves including reserves in affiliates as of 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 15.0% to 9.677% interest

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 expenditures related to Oil and Gas producing activities

(in NOK million)	2008	At 31 December 2007	2006
Unproved properties	61,484	40,513	26,096
Proved properties, wells, plants and other equipment	611,251	526,634	501,472
Total capitalised expenditures	672,735	567,147	527,568
Accumulated depreciation, depletion, amortisation and valuation allowances	(349,428)	(309,527)	(283,428)
Net capitalised expenditures	323,307	257,620	244,140

Net capitalised expenditures related to affiliates as of 31 December 2008 was NOK 4.6 billion.

Expenditures incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
These expenditures include both amounts capitalised and expensed

(in NOK million)	Norway	Outside Norway	Total
Year ended 31 December 2008			
Exploration costs	8,672	9,136	17,808
Development costs [1), 2)]	29,478	14,215	43,693
Acquired proved properties [3)]	-	12,435	12,435
Acquired unproved properties [4)]	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), 2)]	28,428	13,330	41,758
Acquired unproved properties	-	17,133	17,133
Total	34,177	38,962	73,139
Year ended 31 December 2006			
Exploration costs	4,649	9,484	14,133
Development costs [1), 2)]	27,303	14,009	41,312
Acquired unproved properties	511	9,588	10,099
Total	32,463	33,081	65,544

(1) Development costs include investments in Norway in facilities for liquefaction of natural gas and storage of LNG amounting to NOK 90 million in 2008, NOK 661 million in 2007 and NOK 112 million in 2006.
(2) Includes minor development costs in unproved properties.
(3) Includes the acquisition of Anadarco's 50% share in Peregrino, Brazil.
(4) 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 affiliates in 2008 was NOK 448 million.

Results of Operation for Oil and Gas Producing Activities
As required by FAS 69, the revenues and expenses included in the following table reflect only those relating to the oil and gas producing operations of StatoilHydro.

Activities included in StatoilHydro'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, and 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.

(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 operating expenses	(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 operating expenses	(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
Year ended December 2006			
Sales	143	10,640	10,784
Transfers	175,476	20,523	195,999
Total revenues	175,619	31,163	206,783
Exploration expense	(3,480)	(7,170)	(10,650)
Production costs	(12,774)	(4,176)	(16,950)
DD&A	(20,938)	(14,370)	(35,308)
Total operating expenses	(37,192)	(25,716)	(62,908)
Results of operations before tax	138,427	5,447	143,874
Tax expense	(98,994)	(2,133)	(101,127)
Result of operations	39,433	3,314	42,748

The results of operations for oil and gas producing activities of affiliates outside of Norway amounts to NOK 428 million in the year ended December 2008.

Corrections increasing the results of operations for 2007 and 2006 by NOK 9.0 and 10.3 billion, respectively, were made to the previously reported figures.

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 presented. The analysis is computed in accordance with FAS 69, by applying year end market prices, costs, 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. Future net cash flow pre-tax 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 information provided does not represent management's estimate of StatoilHydro's expected future cash flows or value of proved oil and gas reserves. 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. The standardised measure of discounted future net cash flows prescribed under FAS 69 requires assumptions as to the timing and amount of future development and production costs and income from the production of proved reserves. This does not reflect management's judgment and should not be relied upon as an indication of StatoilHydro's future cash flow or value of its proved reserves.

(in NOK million)	Norway	Outside Norway	Total
At 31 December 2008			
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
Standardised measure of discounted future net cash flows related to affiliates	-	2,024	2,024
Total standardised measure of discounted future net cash flows including affiliates	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
At 31 December 2006			
Future net cash inflows	1,643,982	310,129	1,954,111
Future development costs	(113,121)	(36,496)	(149,617)
Future production costs	(321,208)	(53,377)	(374,585)
Future income tax expenses	(939,061)	(70,481)	(1,009,542)
Future net cash flows	270,592	149,775	420,367
10 % annual discount for estimated timing of cash flows	(116,469)	(58,184)	(174,653)
Standardised measure of discounted future net cash flows	154,123	91,591	245,714

Of the NOK 154,376 million of expected future development costs as of 31 December 2008, NOK 92,010 million is expected to be expended within the next three years, as allocated in the table below.

Future development cost

(in NOK million)	2009	2010	2011	Total
Norway	29,904	22,981	15,572	68,457
Outside Norway	11,968	6,558	5,027	23,553
Total	41,872	29,539	20,599	92,010
Future development cost expected to be spent on proved undeveloped reserves	28,224	20,125	12,556	60,905

In 2008, StatoilHydro incurred NOK 56,128 million in development costs, of which NOK 36,955 million related to proved undeveloped reserves.

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

(in NOK million)	2008	2007
Standardised measure at beginning of year	300,770	245,714
Net change in sales and transfer prices and in production (lifting) costs related to future production	(74,453)	239,091
Changes in estimated future development costs	(56,924)	(30,740)
Sales and transfers of oil and gas produced during the period, net of production cost	(234,199)	(189,992)
Net change due to extensions, discoveries, and improved recovery	1,866	15,967
Net change due to purchases and sales of minerals in place	(4,936)	-
Net change due to revisions in quantity estimates	51,574	78,122
Previously estimated development costs incurred during the period	56,128	41,758
Accretion of discount	50,960	(54,374)
Net change in income taxes	92,805	(44,776)
Total change in the standardised measure during the year	(117,179)	55,056
Standardised measure at end of year	183,591	300,770
Change in the standardised measure related to affiliates	2,024	-
Standardised measure at end of year including affiliates	185,615	300,770

Operational statistics

Productive oil and gas wells and developed and undeveloped acreage

The following tables show the number of gross and net productive oil and gas wells and total gross and net developed and undeveloped oil and gas acreage in which StatoilHydro had interests at 31 December 2008.

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

At 31 December 2008		Norway	Outside Norway	Total
Number of productive oil and gas wells				
Oil wells	— gross	927	882	1,809
	— net	368	130	498
Gas wells	— gross	163	100	263
	— net	72	33	105

The total gross number of productive wells as of end 2008 includes 354 oil wells and 15 gas wells with multiple completions or wells with more than one branch.

At 31 December 2008 (in thousands of acres)		Norway	Outside Norway	Total
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	876	1,323	2,199
	— net	328	405	733
Acreage undeveloped	— gross	15,973	71,617	87,590
	— net	8,099	35,231	43,330

Remaining terms of leases and concessions are between one and 37 years.

Net productive and dry oil and gas wells drilled

The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by StatoilHydro in the past two years. Productive wells include wells in which hydrocarbons were found, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Outside Norway	Total
Year 2008			
Net productive and dry exploratory wells drilled	26.1	12.1	38.2
— Net dry exploratory wells drilled	7.2	5.8	13.0
— Net productive exploratory wells drilled	18.9	6.3	25.2
Net productive and dry development wells drilled	27.9	23.7	51.6
— Net dry development wells drilled	0.5	-	0.5
— Net productive development wells drilled	27.4	23.7	51.1
Year 2007			
Net productive and dry exploratory wells drilled	13.2	14.0	27.1
— Net dry exploratory wells drilled	4.5	5.9	10.4
— Net productive exploratory wells drilled	8.7	8.0	16.7
Net productive and dry development wells drilled	34.7	19.7	54.4
— Net dry development wells drilled	0.7	1.0	1.7
— Net productive development wells drilled	34.0	18.7	52.7
Year 2006			
Net productive and dry exploratory wells drilled	11.1	15.1	26.2
— Net dry exploratory wells drilled	6.4	7.3	13.7
— Net productive exploratory wells drilled	4.7	7.8	12.5
Net productive and dry development wells drilled	21.1	14.0	35.1
— Net dry development wells drilled	0.8	-	0.8
— Net productive development wells drilled	20.3	14.0	34.3

Exploratory and development drilling in process

The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by StatoilHydro at December 31, 2008.

At 31 December 2008		Norway	Outside Norway	Total
Number of wells in progress				
Developement Wells	— gross	32	47	79
	— net	13.6	7.7	21.3
Exploratory Wells	— gross	7	9	16
	— net	4.3	2.9	7.2

Average sales price and unit production cost

	Norway	Outside Norway
Year ended 31 December 2008		
Average sales price liquids in USD per bbl	91.5	88.7
Average sales price natural gas in NOK per Sm3	2.4	1.3
Average production costs, in NOK per boe	37.3	42.2
Year ended 31 December 2007		
Average sales price liquids in USD per bbl	70.9	69.1
Average sales price natural gas in NOK per Sm3	1.69	1.17
Average production costs, in NOK per boe	46.3	34.4
Year ended 31 December 2006		
Average sales price liquids in USD per bbl	63.6	60.9
Average sales price natural gas in NOK per Sm3	1.94	1.64
Average production costs, in NOK per boe	26.9	37.5

8.2 Report of independent registered public accounting firms

8.2.1 Report of Ernst & Young AS on the financial statements of StatoilHydro ASA

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of StatoilHydro ASA

We have audited the accompanying consolidated balance sheets of StatoilHydro ASA and subsidiaries ("StatoilHydro") as of 31 December 2008 and 2007, and the related consolidated statements of income, recognised income and expense, and cash flows for each of the three years in the period ended 31 December 2008. 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 did not audit the 2006 financial statements of Hydro Petroleum, a consolidated business (see note 31 to the consolidated financial statements), which statements reflect total revenue and net income of NOK 97,910 million and NOK 11,093, respectively, for the year ended 31 December 2006. Those statements were audited by other auditors whose report, which has been furnished to us, included an explanatory paragraph that refers to certain allocations that were required to prepare such financial statements. Our opinion, as of 31 December 2006, insofar as it relates to the amounts included for Hydro Petroleum, is based solely on the report of the other auditors.

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 and, for 2006, the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based upon our audits and, for 2006, the report of the other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of StatoilHydro at 31 December 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended 31 December 2008, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board and International Financial Reporting Standards as adopted by the European Union.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), StatoilHydro's internal control over financial reporting as of 31 December 2008, 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 2009 expressed an unqualified opinion thereon.

Ernst & Young AS
Stavanger, Norway
17 March 2009
except for Note 33, as to which the date is
24 March 2009

8.2.2 Report of Ernst & Young AS on StatoilHydro's internal control over financial reporting

The Board of Directors and Shareholders of StatoilHydro ASA

We have audited StatoilHydro ASA's ("StatoilHydro") internal control over financial reporting as of 31 December 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("the COSO criteria"). StatoilHydro's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's report on internal control of financial reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, StatoilHydro maintained, in all material respects, effective internal control over financial reporting as of 31 December 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of StatoilHydro ASA and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, recognised income and expense, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated 17 March 2009 expressed an unqualified opinion thereon.

Ernst & Young AS

Stavanger, Norway
17 March 2009
except for Note 33, as to which the date is
24 March 2009

8.2.3 Report of Deloitte AS on the carve-out financial statements of Hydro Petroleum

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and shareholders of Norsk Hydro ASA

We have audited the carve-out combined statements of income, statements of comprehensive income, and cash flows of Hydro Petroleum for the year ended 31 December 2006 (not presented separately herein). These carve-out combined financial statements are the responsibility of Norsk Hydro ASA's management. Our responsibility is to express an opinion on these carve-out combined financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Hydro Petroleum is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Hydro Petroleum's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such carve-out combined financial statements present fairly, in all material respects, the results of its operations and its cash flows of Hydro Petroleum for the year ended 31 December 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the 2006 financial statements have been restated.

As discussed in Note 1 to the financial statements, the carve-out combined financial statements also include certain allocations from Norsk Hydro ASA. These allocations may not be reflective of the actual level of costs or debt which would have been incurred had Hydro Petroleum operated as a separate entity apart from Norsk Hydro ASA. Hydro Petroleum also changed its method of accounting for the recognition of over/under funded status of retirement plans in 2006 to conform to newly adopted accounting principles.

As discussed in Note 27 to the financial statements, International Financial Reporting Standards as published by the International Accounting Standards Board vary in certain significant respects from accounting principles generally accepted in the United States of America. Information relating to the nature and effect of such differences is presented in Note 27 to the carve-out combined financial statements.

Deloitte AS
Oslo, Norway
29 March 2007 (08 May 2007 as to the effects of the restatement discussed in Note 1 and 21 February 2008 for Note 27)

9 Terms and definitions

Organisational abbreviations:

- ACG - Azeri-Chirag-Gunashli
- ACQ - Annual Contract Quantity
- APA - Awards in Predefined Areas
- AFP - Agreement-based Early Retirement Plan
- AnLNG - Angola LNG
- BTC - Pipeline Baku-Tbilisi-Ceyhan
- BTL - Biomass-to-liquids Process
- CCS - Carbon Capture and Storage
- CHP - Combined heat and power plant
- CO_2 - Carbon Dioxide
- E&P - Exploration & Production
- EEA - European Economic Agreement
- EFTA - European Free Trade Association
- EGR - Exhaust Gas Recirculation
- EMTN - Euro Medium Term Note
- EPN - Exploration & Production Norway Business Area
- EPSA - Exploration Production Sharing Agreement
- FCC - Fluid Catalytic Cracking
- FPSO - Floating Production Storage Offloading
- FDP - Field Development Plan
- GBS - Gravity-Based Structure
- GDP - Gross Domestic Product
- GEP - Gas Export Project
- GoM - Gulf of Mexico
- GTL - Gas to Liquids
- HSE - Health, Safety, Environment
- HTHP - High-temperature/high pressure
- IASB - International Accounting Standards Board
- IEA - International Energy Agency
- IFRS - International Financial Reporting Standards
- INT - International Exploration & Production business area
- IO - Integrated Operations
- IOR - Increased Oil Recovery
- ISG - In Salah Gas
- KEP2010 - Karstø Upgrading Project
- LNG - Liquefied Natural Gas
- LPG - Liquefied Petroleum Gas
- M&M - Manufacturing and Marketing business area
- MPE - Norwegian Ministry of Petroleum and Energy
- NAOSC - North American Oil Sands Corporation
- NCS - Norwegian Continental Shelf
- NG - Natural Gas Business Area
- NGO - Non Governmental Organization
- NIOC - National Iranian Oil Company
- NOC - National Oil Companies
- NOK - Norwegian Kroner
- NO_x- Nitrogen Oxide
- NSAB - Norwegian Standard Accounting Board
- OECD - Organisation of Economic Co-Operation and Development
- OTC - Over the Counter
- OTS - Oil Trading and Supply Department
- PBO - Project Benefit Obligation
- PDO - Plan for Development and Operation
- PRO - Projects Functional Area
- PSA - Production Sharing Agreement
- R&D - Research and Development
- ROACE - Return on Average Capital Employed
- RSS - Rotary Steerable System

- SAGD - Steam Assisted Gravity Drainage
- SCP - South Caucasus Pipeline System
- SDFI - Norwegian State's Direct Financial Interest
- SORIE - Statement of Recognised Income and Expense
- TAP - Trans Adriatic Pipeline
- TNE - Technology & New energy Functional Area
- TSP - Technical Service Provider
- UKCS - UK Continental Shelf
- USD - United States Dollar
- ÅTS - Åsgard Transport System

Metric abbreviations etc:
- bbl - barrel
- mbbl - thousand barrels
- mmbbl - million barrels
- boe - barrels-of-oil equivalent
- mboe - thousand barrels-of-oil equivalent
- mmboe - million barrels-of-oil equivalent
- mmcf - million cubic feet
- bcf - billion cubic feet
- tcf - trillion cubic feet
- scm - standard cubic metre
- mcm - thousand cubic metres
- mmcm - million cubic metres
- bcm - billion cubic metres
- mmtpa - million tonnes per annum
- km - kilometre
- ppm - part per million
- one billion - one thousand million

Equivalent measurements are based upon:
- 1 barrel equals 0.134 tonnes of oil (33 degrees API)
- 1 barrel equals 42 US gallons
- 1 barrel equals 0.159 standard cubic metres
- 1 barrel of oil equivalent equals 1 barrel of crude oil
- 1 barrel of oil equivalent equals 159 standard cubic metres of natural gas
- 1 barrel of oil equivalent equals 5,612 cubic feet of natural gas
- 1 barrel of oil equivalent equals 0.0837 tonnes of NGLs
- 1 billion standard cubic metres of natural gas equals 1 million standard cubic metres of oil equivalent
- 1 cubic metre equals 35.3 cubic feet
- 1 kilometre equals 0.62 miles
- 1 square kilometre equals 0.39 square miles
- 1 square kilometre equals 247.105 acres
- 1 cubic metre of natural gas equals one standard cubic metre of natural gas
- 1000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1000 British thermal units (btu)
- 1 tonne of NGLs equals 1.9 standard cubic metres of oil equivalents
- 1 degree Celsius equals minus 32 plus five-ninths of the number of degrees Fahrenheit

Miscellaneous terms:
- Biofuel: A solid, liquid or gaseous fuel derived from relatively recently dead biological material and is distinguished from fossil fuels, which are derived from long dead biological material.
- BOE: Barrels of oil-equivalent A measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content.
- Carbon footprint: Total set of greenhouse gas emissions caused directly and indirectly by an individual, organization, event or product.
- Condensates: The heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha
- Crude oil, or oil: Includes condensate and natural gas liquids
- Development: The drilling, construction, and related activities following discovery that are necessary to begin production of crude oil and natural gas fields.
- Downstream: The selling and distribution of products derived from upstream activties.

- Equity and entitlement volumes of oil and gas: Equity volumes represent volumes produced under a Production Sharing Agreement (PSA) that correspond to StatoilHydro's percentage ownership in a particular field. Entitlement volumes, on the other hand, represent StatoilHydro's share of the volumes distributed to the partners in the field, which are subject to deductions for, among other things, royalties and the host government's share of profit oil. Under the terms of a PSA, the amount of profit oil deducted from equity volumes will normally increase with the cumulative return on investment to the partners and/or production from the licence. The distinction between equity and entitlement is relevant to most PSA regimes, whereas it is not applicable in most concessionary regimes such as those in Norway, the UK, Canada and Brazil. The overview of equity production provides additional information for readers, as certain costs described in the profit and loss analysis were directly associated with equity volumes produced during the reported years.
- FCC: Fluid catalytic cracking A process used to convert the high-boiling hydrocarbon fractions of petroleum crude oils to more valuable gasoline, gases and other products.
- GTL: Gas to liquids, means the technology used for chemical conversion of natural gas into transportable liquids (diesel and naphtha) and specialty products (base oils).
- Heavy Oil: Crude oil with high viscosity (typically above 10 cp), and high specific gravity. The API classifies heavy oil as crudes with a gravity below 22.3° API. In addition to high viscosity and high specific gravity, heavy oils typically have low hydrogen-to-carbon ratios, high asphaltene, sulfur, nitrogen, and heavy-metal content, as well as higher acid numbers.
- High Grade: Relates to selectively harvesting goods, to cut the best and leave the rest. In reference to exploration and production this entails strict prioritization and sequencing of drilling targets.
- Hydro: A reference to the oil and energy activities of Norsk Hydro ASA which merged with Statoil ASA to form StatoilHydro.
- IOR: Increased oil recovery is used about actual measures resulting in an increased oil recovery factor fromj a reservoir as compared with the expected value at a certain reference point in time. IOR comprises both of conventional and emerging technologies.
- LNG: Liquefied Natural Gas,lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG: Liquefied petroleum gas and consists primarily of propane and butane, which turn liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels.
- Midstream: Processing, storage, and transport of crude oil, natrual gas, natural gas liquids and sulphur.
- Naphtha is an inflammable oil obtained by the dry distillation of petroleum
- Natural gas: Petroleum that consists principally of light hydrocarbons. It can be divided into 1) lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and 2) wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL: Natural gas liquids, light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- Oil sands: A naturally occurring mixture of bitumen, water, sand, and clay. A heavy viscous form of crude oil.
- Petroleum: A collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from the elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons predominate, it is described as an oil field. An oil field may feature free gas above the oil and contain a quantity of light hydrocarbons, also called associated gas.
- Proved reserves: Proved reserves are those reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, and using existing technology. They are the only type the U.S. Securities and Exchange Commission allows oil companies to report.
- Share turnover: Turnover of shares is a measure of stock liquidity calculated by dividing the total number of shares traded over a period by the average number of shares outstanding for the period. The higher the share turnover, the more liquid the share of the company.
- Syncrude: The output from bitumen extra heavy oil upgrader facility used in connection with oil sand production.
- Upstream: Includes the searching for potential underground or underwater oil and gas firleds, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface.
- VOC: Includes the searching for potential underground or underwater oil and gas firleds, drilling of exploratory wells, subsequent operating wells which bring the liquids and or natural gas to the surface.
- Økokrim: Prosecution of Economic and Environmental Crime in Norway

10 Forward looking statements

This Annual Report on Form 20-F contains forward-looking statements that involve risks and uncertainties, in particular in the sections "Business overview" and "Operational review". In some cases, we use words such as "aim", "anticipate", "believe", "expect", "intend", "may", "plan", "should", "target" and similar expressions to identify forward-looking statements. All statements other than statements of historical fact, including, among others, statements regarding our future financial position; business strategy; projected impact of economic downturn; competitive position; expectations of the synergies produced by our recent acquisitions, such as our interest in the Marcellus shale gas development and Peregrino field; budgets; reserve information; reserve replacement rates; reserve recovery factors; projected levels of capacity; oil and gas production forecasts; production growth; oil, gas and alternative fuel prices; oil, gas and alternative fuel supply and demand; renewable energy industry outlook; projected operating costs; exploration expenditure; estimates of capital expenditure; expected exploration and development activities and plans; start-up dates for upstream and downstream activities; projected impact of HSE regulations; HSE goals and objectives of management for future operations; plans for payment of dividends and amounts of dividends are forward-looking statements. You should not place undue reliance on these forwardlooking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report on Form 20-F.

These forward-looking statements reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that will occur in the future. There are a number of factors that could cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements, including levels of industry product supply, demand and pricing; currency exchange rates; the political and economic policies of Norway and other oil-producing countries; general economic conditions; political stability and economic growth in relevant areas of the world; global political events and actions, including war, terrorism and sanctions; changes in laws and governmental regulations; the timing of bringing new fields on stream; material differences from reserves estimates; an inability to find and develop reserves; adverse changes in tax regimes; the development and use of new technology; geological or technical difficulties; operational problems; the actions of competitors; the actions of field partners; natural disasters and adverse weather conditions and other changes to business conditions; and other factors discussed elsewhere in this report.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot assure you that our future results, level of activity, performance or achievements will meet these expectations. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Unless we are required by law to update these statements, we will not necessarily update any of these statements after the date of this Annual Report, either to make them conform to actual results or changes in our expectations.

11 Signature page

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this Annual Report on its behalf.

STATOILHYDRO ASA
(Registrant)

By: /s/ Eldar Sætre
Name: Eldar Sætre
Title: Chief Financial Officer

Dated: 24 March, 2009

12 Exhibits

The following exhibits are filed as part of this Annual Report:

Exhibit 1	Articles of Association of StatoilHydro ASA, as amended (English translation) (incorporated by reference to Exhibit 1 to Statoil's Annual Report and Form 20-F/A for the fiscal year ended December 31, 2006 File No. 1-15200.)
Exhibit 4(a)(i)	Technical Services Agreement between Gassco AS and Statoil ASA, dated February 27, 2002 (incorporated by reference to Exhibit 4 to Statoil's Annual Report and Form 20-F for the fiscal year ended December 31, 2001 File No. 1-15200.)
Exhibit 4(b)	Merger Plan (included as Appendix A to the circular/prospectus contained in Amendment No. 3 to the Registration Statement on Form F-4/A filed on May 22, 2007 File No. 333-141445.)
Exhibit 4(c)(i)	Employment agreement with Helge Lund (English translation) (incorporated by reference to Exhibit 4(c) to Statoil's Annual Report and Form 20-F for the fiscal year ended December 31, 2003 File No. 1-15200.)
Exhibit 7	Calculation of ratio of earnings to fixed charges.
Exhibit 8	Subsidiaries (see Section 3.7.5 included in this Annual Report).
Exhibit 12.1	Rule 13a-14(a) Certification of Chief Executive Officer.
Exhibit 12.2	Rule 13a-14(a) Certification of Chief Financial Officer.
Exhibit 13.1	Rule 13a-14(b) Certification of Chief Executive Officer.*
Exhibit 13.2	Rule 13a-14(b) Certification of Chief Financial Officer.*
Exhibit 15(a)(i)	Consent of Ernst & Young AS.
Exhibit 15(a)(ii)	Consent of Deloitte AS relating to the financial statements of Hydro Petroleum.
Exhibit 15(a)(iii)	Consent of DeGolyer and MacNaughton.

* Furnished only

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of StatoilHydro ASA and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

13 Cross Reference

Cross reference to Form 20-F