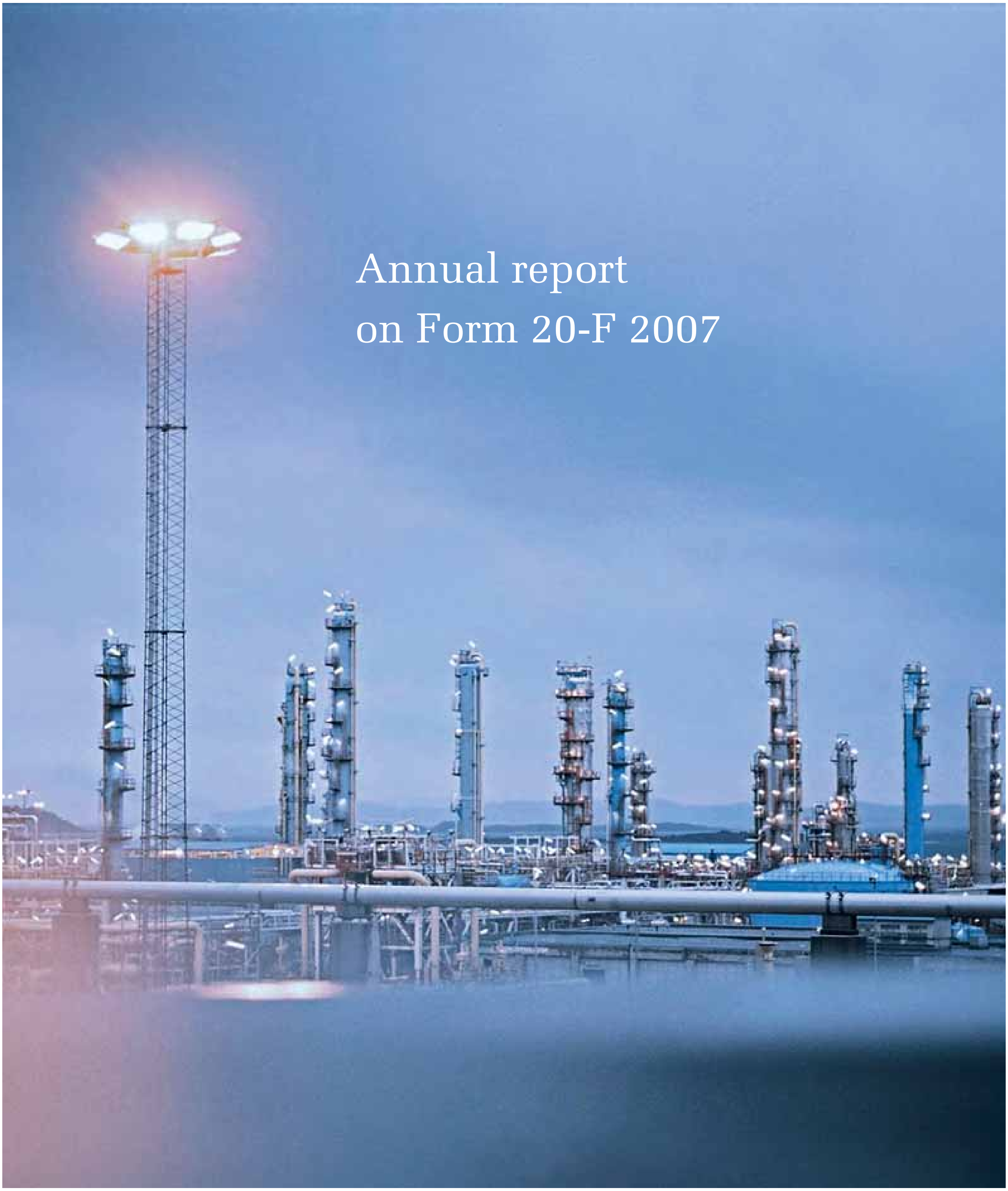

Annual report on Form 20-F 2007

StatoilHydro

Annual Report on Form 20-F 2007

Annual Report on Form 20-F 2007

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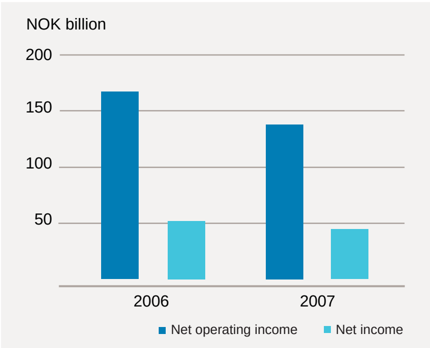
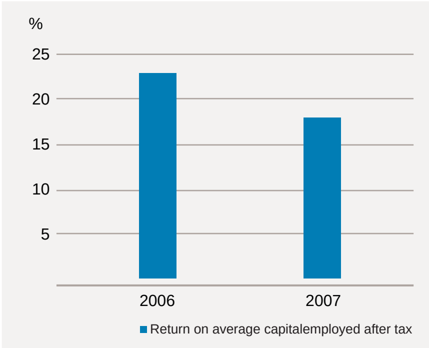
1 Introduction

1.1 Key figures

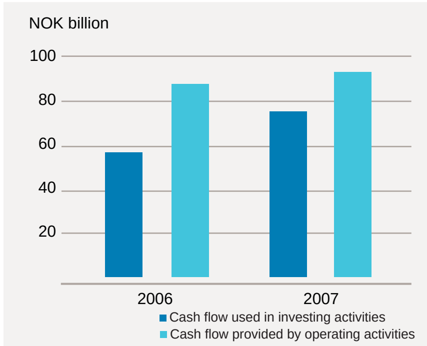
INCOME



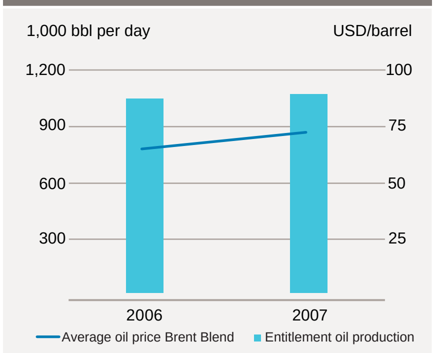
RETURN



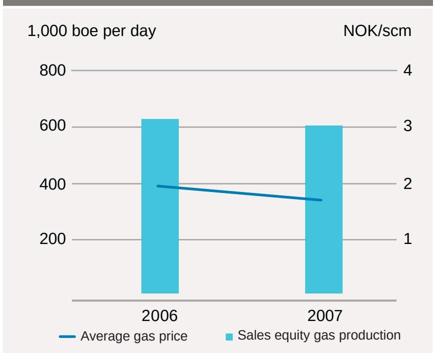
CASH FLOW



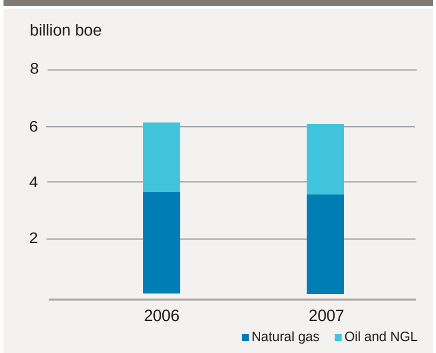
OIL PRODUCTION/PRICE



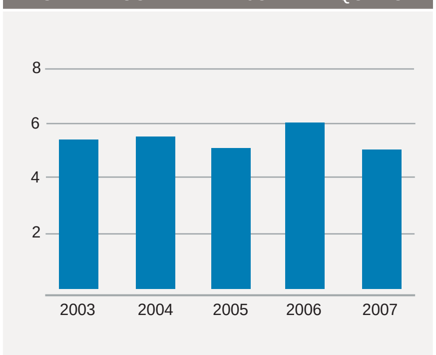
GAS PRODUCTION/PRICE



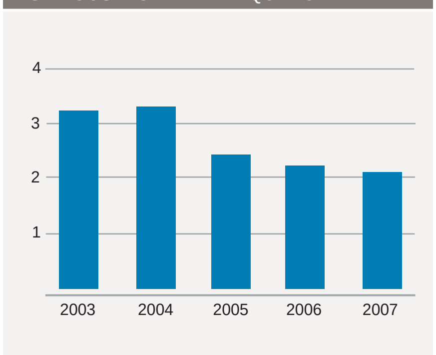
PROVED OIL AND GAS RESERVES



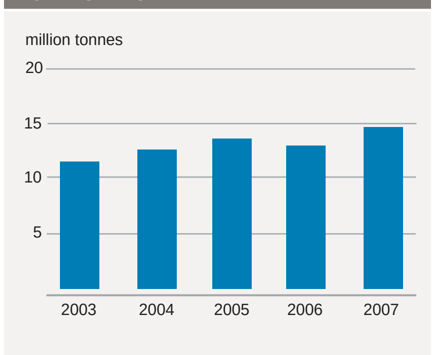
TOTAL RECORDABLE INJURY FREQUENCY



SERIOUS INCIDENT FREQUENCY



CARBON DIOXIDE



1.2 Financial highlights

(in NOK million, except per share amounts)	For the year ended 31 December 2007	2006
Financial information		
Total revenues and other income	**522,797**	521,482
Net operating income	**137,204**	166,164
Net income	**44,641**	51,847
Cash flows provided by operating activities	**93,926**	88,593
Cash flows used in investing activities	**75,112**	57,175
Interest-bearning debt	**50,539**	54,772
Net interest-bearing debt	**25,461**	43,779
Net debt to capital employed	**12.4%**	20.5%
Return on average capital employed after tax	**17.9%**	22.9%
Operational information		
Combined oil and gas production (thousand boe/day)	**1,724**	1,708
Proved oil and gas reserves (million boe)	**6,010**	6,101
Production cost (NOK/boe)	**44.1**	28.4
Reserve replacement ratio (three-year average)	**81%**	76%
Share information		
Ordinary and diluted earnings per share	**13.80**	15.82
Share price at Oslo Stock Exchange on 31 December	**169.00**	165.25
Dividend paid per share (1)	**8.50**	9.12
Weighted average number of ordinary shares outstanding	**3,195,866,843**	3,230,849,707

(1) See Shareholders information section for a description of how dividends are determined and share repurchases.

StatoilHydro is publishing financial data in accordance with IFRS for the first time in this Annual Report and Form 20-F 2007. StatoilHydro did not publish financial data in accordance with IFRS in prior years, as we previously presented financial data in accordance with US GAAP. For this reason, we have not provided selected financial data for 2005, 2004 and 2003 in this Annual Report and Form 20-F 2007. Selected financial data for those years presented in accordance with US GAAP is included in our 2006 Annual Report on Form 20-F.

1.3 Events and highlights

- The StatoilHydro merger was completed on schedule and the new organisation has successfully been put in place.
- Fourteen new projects were sanctioned in 2007. Among these were our Peregrino heavy oil development in Brazil, Pazflor in Angola, and the Leismer demonstration project in Canada. In August, the authorities in Alberta granted approval for the development of the Leismer SAGD Demonstration Project.
- Fifteen new projects came on stream in 2007, 10 on the NCS and five internationally.
- Ormen Lange commenced production in September 2007. A gigantic development project has been completed and the Ormen Lange field is on stream. Through this project we have demonstrated industry-leading expertise in total gas value chain development.
- The StatoilHydro-operated Snøhvit field commenced production in September 2007. In October, the first tanker with a cargo of liquefied natural gas (LNG) from the Snøhvit field left the port at Melkøya near Hammerfest in Northern Norway.
- The StatoilHydro-operated Statfjord Late Life project commenced production in November as the Tampen Link Pipeline was opened for gas exports. The Tampen Link pipeline transports gas from the Statfjord field to the Flags transport system, which runs from the UK's Brent field to St. Fergus in Scotland.
- In 2007, we delivered the world's first commercial subsea separation, boosting and injection system on the Tordis field. The facilities were connected to Gullfaks C and production started in December 2007.
- International entitlement production grew by 31% during 2007. New StatoilHydro equity production capacity of approximately 40 mboe per day was added from new fields coming on stream: Q, San Jacinto and Spiderman in the US Gulf of Mexico and Rosa, Marimba North and Mondo (which came on stream on 1 January 2008) in Angola.
- Our heavy oil position was considerably strengthened by the acquisitions of North American Oil Sands Corporation in Canada, the Mariner/Bressay/Broch discoveries in the UK, and remaining share in the Peregrino development in Brazil. (The transaction is subject to government approval.) We are operator for all of these projects.
- A Framework agreement was signed with Gazprom to become a partner in the Shtokman development phase 1, through participation in the Shtokman Development Company.

- Regular deliveries of Shah Deniz gas to Turkey commenced in July 2007.
- The carbon dioxide test centre Mongstad partnership was established in June 2007.

1.4 StatoilHydro's annual report

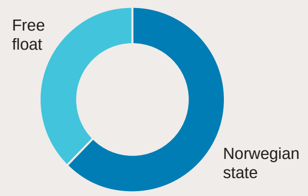
StatoilHydro's Annual Report on Form 20-F for the year ended 31 December 2007 ("Annual Report on Form 20-F") is available online at www.statoilhydro.com StatoilHydro is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, StatoilHydro files its Annual Report on Form 20-F 2007 and other related documents with the SEC. It is also possible to read and copy documents referred to in the Annual Report on Form 20-F 2007 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. Please call the SEC on 1-800-SEC-0330 for further information about the public reference rooms and their copy charges. The report can also be downloaded from the SEC website at www.sec.gov

2 Business overview

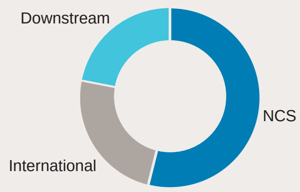
2.1 Our business

StatoilHydro ASA is a technology-based oil and gas company based in several locations in Norway and internationally. We are the leading operator on the Norwegian continental shelf (NCS) and we are also experiencing strong growth in our international production.

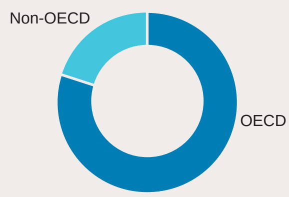
OWNERSHIP STRUCTURE



FIXED ASSETS

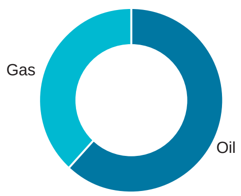


UPSTREAM ASSETS



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). Our head office is at Forusbeen 50, NO-4035 Stavanger, Norway. Our telephone number is +47 51 99 00 00. Stavanger, Bergen and Oslo are our largest locations.

OIL AND GAS PRODUCTION



Entitlement oil and gas production outside Norway represented 18% of our total output, which averaged 1.724 mmboe per day in 2007.

As of 31 December 2007, we had proved reserves of 2,389 mmbbl of oil and 576 bcm (equivalent to 20.3 tcf) of natural gas, corresponding to aggregate proved reserves of 6,010 mmboe.

We are represented in 40 different countries and are engaged in exploration and production activities in 24 of them. At 31 December 2007, 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 2,300 service stations in Scandinavia, Poland, the Baltic States and Russia.

We contribute to developing new energy resources, have ongoing activities in the fields of wind power and bio fuels and are at the forefront with respect to technologies for carbon capture and storage.

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

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

2.2 Our history

On 1 October 2007, the oil and gas assets of Norsk Hydro ASA (Hydro Petroleum) were merged with Statoil ASA, 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 reflect the developments of former Statoil ASA and Hydro Petroleum on a combined basis for all periods presented.

Statoil was founded by a decision of the Norwegian Storting (parliament) in 1972 and 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 it changed its name to Statoil ASA.

Norsk Hydro's involvement in the oil and gas industry started in 1965, when it was awarded licences by the Norwegian State to explore for petroleum on the NCS.

Hydro participated in the discovery of the Ekofisk field in 1969 and the Frigg field in 1971. The development of these discoveries brought it into the petroleum refining and marketing business. In 1975, it began oil refining operations at Mongstad in Norway.

In 1974, Mobil discovered the Statfjord field in the North Sea, which was to have enormous significance for further developments. During the development of Statfjord, one of the world's largest offshore oilfields, we encountered great challenges. Statfjord came on stream in 1979 and Statoil took over as operator eight years later. StatoilHydro has a 44% interest in the field.

The 1980s saw us become a major player in the European gas market through 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. StatoilHydro became a leading company 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 in alliance with BP.

In recent years, our business has grown as a result of substantial investments, including several acquisitions. This include among other the acquisition of Saga Petroleum AS in 1999, several major acquisitions in the Gulf of Mexico, acquisitions of oil sand leases in Canada in 2007, the 24% equity interest in the Shtokman Development Company and most recently the acquisition of the remaining share in the Peregrino field in Brazil (the transaction is subject to government approval), in which we also become the operator. For more information of this acquisition, see report section Operational review-International E&P.

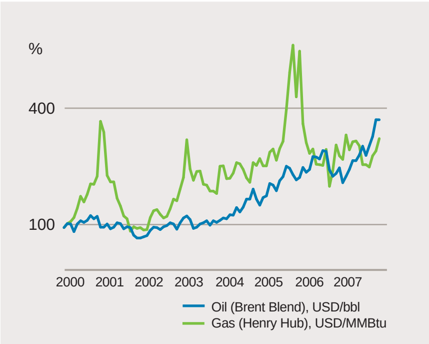
2.3 Statements regarding competitive position

Statements referring to StatoilHydro's competitive position in the Business Overview and Operational Overview 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.

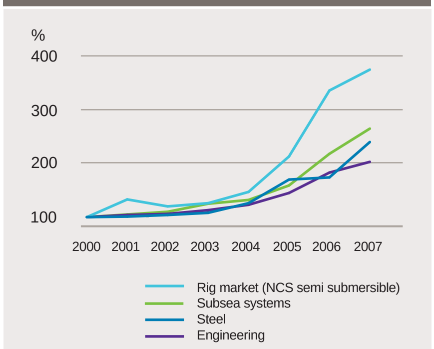
2.4 Strategy

2.4.1 Business environment

OIL AND GAS PRICE



GLOBAL MARKET DEVELOPMENTS



Macroeconomic outlook
Strong global growth, and in particular China's entry into the global economy, has led to high commodity prices. Contrary to previous periods with high oil prices, this time the global economy has managed to maintain robust growth. The outlook for the global economy is still positive, and Global Insight expects global growth to be around 3.5% over the next four years, before declining somewhat to a long-term growth trend of around 3%. Coupled with the effects of the weak US economy and potential spill-over effects, the recent turmoil in the financial markets has increased the downside risk in the short term. On the other hand, the positive growth signals from Asian markets are expected to counterbalance the downside risk.

Crude oil price developments
Brent Dated gradually increased by USD 37 per barrel during 2007 to average USD 72.4 per barrel. The WTI (West Texas Intermediate) grade saw similar price growth and it also averaged USD 72.4 per barrel in 2007.

At the start of 2007, oil prices were relatively soft due to high oil stocks and a mild winter. However, Opec production cuts in late 2006 and spring 2007 led to an increasingly tight balance between global supply and demand for oil. Major OECD oil stocks were trimmed significantly during the year. Non-Opec output rose slightly as oil production from the former Soviet Union and increased bio fuel production more than compensated for lower North Sea and Mexican production. Oil demand remained relatively supportive, with growth of one million barrels per day, mainly due to continued growth in Asia and the Middle East.

Increased national control of resources
In the short term, the upstream exploration and production industry in particular is expected to experience strong margins based on past investment, while at the same time facing increasing challenges in gaining access to new attractive investment opportunities. This is due to the changing conditions and the increase in government take resulting from higher oil prices, the increase in the amount of capital chasing limited exploration and production opportunities, a more cost sensitive environment and lack of qualified experts in a high activity environment.

High oil prices, resource nationalism and the focus on energy independence, climate change and local employment, have fuelled a strong increase in interest in alternatives to conventional upstream oil and gas, such as unconventional oil and gas, new energy, natural gas value chains and energy efficiency.

The International Energy Agency's World Economic Outlook 2007 estimates that cumulative investments in energy value chains globally will be approximately USD 22 trillion in 2006 dollars during the period 2006-2030, which will mean large future investment opportunities for energy companies.

2.4.2 A strategy for growth

StatoilHydro's strategy is to maximise value and potential on the NCS while growing our international production. We are an upstream focused and technology driven energy company with strong gas and downstream positions.

With continued focus on HSE as a competitive advantage and a basis of our operations, we concentrate our efforts on four areas:

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

In the short term, we plan to focus on predictable and efficient operation by realising the potential value resulting from the merger of Statoil ASA with the oil and gas assets of Norsk Hydro ASA. In the longer term, our focus will be on developing prospects and projects that will enable us to excel and profitably grow. We endeavour to act in a responsible and sustainable manner by continuously improving energy and environmental efficiency in our production processes.

Maximising long-term value creation from the NCS

As a consequence of the merger of Statoil ASA with Norsk Hydro ASA's oil and gas assets, we are in a unique position on the NCS. Our combined asset base, experience and technical know-how will enable us to fully utilise these resources. The NCS portfolio is expected to continue to be the company's core activity area, income generator and technology base for many years to come.

We believe the potential for further exploration on the NCS is significant, and we aim to be the industrial architect and driving force in utilising this potential to the maximum. We will strive to improve HSE performance, regularity and drilling efficiency, we will use Increased Oil Recovery (IOR) measures where appropriate and maximise the potential of the merged company. Our focus will be on delivering results and optimising our portfolio in order to maximise value creation.

Building profitable international growth

The company's growth beyond 2012 is mainly expected to take place in the international arena. Our short to medium-term focus is on delivering our current projects on time, at agreed cost and quality. We plan to make the most of our NCS resources, capabilities and technical experience to develop new business opportunities internationally.

In the longer term, we believe that growth in our international assets will transform the structure and profile of the company. We expect to become more diversified, not only in geographical terms, but also in terms of production methods. This was demonstrated through the acquisition of the Canadian company North American Oil Sands Corporation (NAOSC) and the development of the Peregrino field (heavy oil) off the coast of Brazil, both of which present new challenges and opportunities in terms of applying our technology and experience to a different type of oil production than in the North Sea.

In connection with the company's international growth our main focus will be on utilising our core expertise in areas such as deepwater, harsh environment, heavy oil and gas value chains to exploit new opportunities around the world. We believe that our skills, experience and technological ability will give us a competitive advantage in these areas. We intend to achieve this growth through an ambitious exploration programme, developing and delivering from our current international assets, and, as appropriate, acquiring new assets which complement our portfolio.

Developing profitable midstream and downstream positions

Compared with many of our peers, we have a strong upstream focus in terms of our total value and asset base. However, we also have a sizeable midstream and downstream portfolio in retailing, marketing, trading, refining and storage of oil and gas products. We are one of the largest seller of crude oil in the world, and our refineries, gas processing plants and service stations support our upstream positions. Our ambition is to maximise value for the company by making the most of the opportunities which these value chains represent.

Creating a platform for new energy

We are a leading industry player in the field of carbon capture and storage. Our ambition is to further develop our technology and capabilities in this area to create a profitable business and to reduce emissions. We are also looking into the opportunities for commercially sound investments in renewable energy chains. We have initiated projects in the areas of wind power and bio fuels, setting the stage for further expansion in this area, such as offshore wind farms.

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 37 developed fields that collectively produced more than three mmboe per day in 2007, which represented about 80% of the total production from the NCS. In 2007, our average daily oil and NGL production was 817.9 mboe and our daily gas production was 95.2 mmcm (3.4 bcf), totalling 1.417 mmboe per day.

We are well positioned in terms of exploration acreage throughout the licensed parts of the NCS, both within and outside our core production areas. We participate in 225 licences on the NCS and are operator for 175 of them.

As of 31 December 2007, EPN had proved reserves of 1,604 mmbbl of crude oil and 535 bcm (18.9 tcf) of natural gas, which represents an aggregate of 4,971 mmboe.

2.5.2 Strategy

There are several factors that are expected to contribute to the achievement of our production goals on the NCS. They include increased production efficiency, increased drilling efficiency, cost-effective operations, improved recovery from existing fields, development of new discoveries, the proving of new reserves through intensive exploration activity, increased access to new licences, focus on health, safety and the environment (HSE) and optimal use of existing infrastructure.

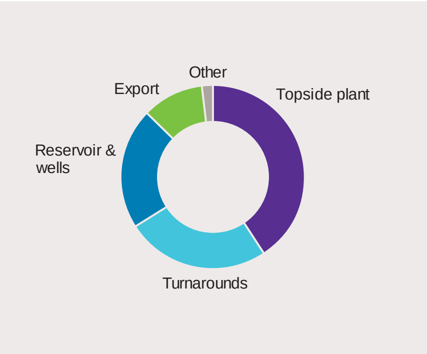
Stable production

As fields on the NCS mature and production declines, high priority will be given to implementing measures to increase production from existing fields. The main measures in this context are more efficient drilling and increased production time on our platforms.

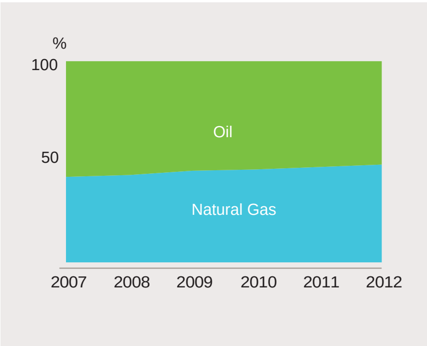
Higher regularity is expected to be achieved through improved well work, better reservoir management, de-bottlenecking of export infrastructure, better planning of turnarounds and fewer topside plant failures.

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 improved oil recovery measures.

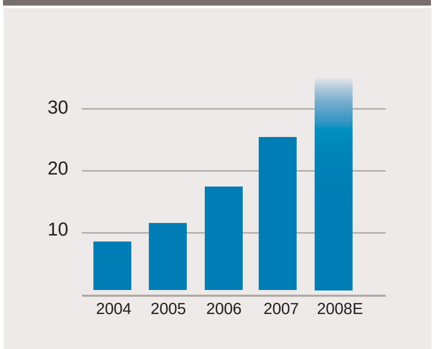
PRODUCTION LOSS



INCREASED GAS PRODUCTION



EXPLORATION WELLS



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 in order to secure high production.

Gas position

The proportion of natural gas from our NCS portfolio is increasing. We have a flexible transportation system, with six different landing points and flexibility in terms of gas deliveries from gas producers such as Troll and Oseberg.

Finding and developing new resources

We intend 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. Of the 35 wells that are planned to be drilled in 2008, 30 are located in areas with existing infrastructure, and five will be drilled in frontier areas. Access to new prospective acreage is necessary in order to maintain a high production level. Active infrastructure-led exploration is also a key factor in extending the life of the infrastructure in the tail-end production phase.

Safe and efficient operations are essential to our business

All activities in StatoilHydro will be conducted with high focus on HSE in order to achieve our goal of avoiding harm to people and the environment. The implementation of Integrated Operations (IO) is expected to improve cooperation across activities and organisations, both offshore and onshore. Implementing IO also has the potential to increase value through higher production, higher regularity and cost reductions offshore. Upgrading and modification programmes for offshore installations are also planned with a view to maintaining safe and efficient operations.

Industrial architect for NCS

Due to our central position on the NCS, we have a responsibility to maintain a stable relationship with suppliers, competitors, government and other stakeholders. The NCS is a world-class arena for innovation and technological development. StatoilHydro is also a leader in the use of new technology on the NCS, including drilling and subsea technology, new solutions to reduce costs and the use of new technology to develop discoveries.

As the largest operator on the NCS, we have a responsibility to take the lead in the development of optimal area solutions and overall development of the NCS.

2.5.3 Key events

- Ormen Lange commenced production in September 2007.
  A gigantic development project has been completed and the Ormen Lange field is on stream. On 1 December 2007 the operatorship was transferred to Shell.
- The StatoilHydro-operated Snøhvit field commenced production in September 2007.
  In October, the first tanker with a cargo of liquefied natural gas (LNG) from the Snøhvit field left the port at Melkøya near Hammerfest in Northern Norway.
- The StatoilHydro-operated Statfjord Late Life project commenced production in November as the Tampen Link Pipeline was opened for gas exports.
- Tordis IOR's subsea separation facilities were installed in August 2007.
  The facilities were connected to Gullfaks C and production started in December 2007.

2.6 International E&P

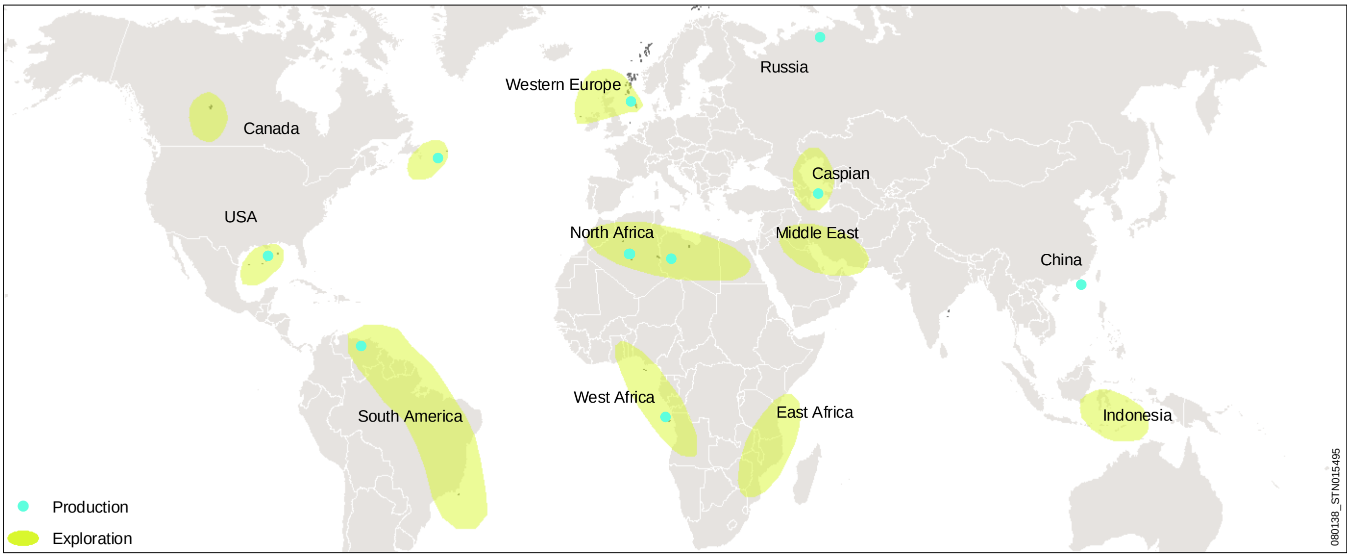
2.6.1 Introduction

International Exploration & Production (INT) is responsible for exploration, development and production of oil and gas outside the NCS. The figure above shows our exploration and production areas.

In 2007, the business area had production from Canada, the US Gulf of Mexico, Venezuela, Algeria, Libya, Angola, Azerbaijan, the UK, China and Russia. In 2007, INT produced approximately 20% of StatoilHydro's total equity production of oil and gas, and our share is expected to increase significantly in the future.

We have exploration activities in North America (Canada and the US), Latin America (Brazil, Cuba and Venezuela.), North Africa (Algeria, Egypt, Libya and Morocco), Sub-Saharan Africa (Angola, Mozambique, Nigeria and Tanzania), the Caspian region (Azerbaijan), Western Europe (Denmark, the Faeroe Islands, Ireland and the UK), the Middle East (Iran) and Indonesia.

The main development projects that we are involved in are in Canada, the US GoM, Brazil, Angola, Nigeria, Azerbaijan and Ireland, and we believe we are well positioned for further growth through a substantial non-sanctioned project portfolio.



2.6.2 Strategy

INT is responsible for exploration, development and production of oil and gas resources outside the NCS. This includes:

- Gaining access to new prospective hydrocarbon acreage and/or discovered reserves
- Commercial development of the international oil and gas portfolio, including infrastructure

INT is driving the company's future upstream growth ambition. The strategy is to access new resources through high quality exploration activities and focused business development by utilising our technological experience and project execution skills. Resources are moved effectively into production through our demonstrated project execution and operational experience from the NCS.

Over the last decade, we have concentrated our efforts to access new resources around four focus areas; deepwater; harsh environment; gas value chains and heavy oil, all of which draw on our experience from the NCS.

The international access strategy has proven successful, and our resource base has increased in terms of both produced volumes and technological and geographical breadth. INT's near-term focus is on strengthening our presence in existing producing regions in order to achieve stronger positioning. Gaining operatorships and building regional organisational hubs is a part of this strategy. As new fields come on stream, they will complement our existing international activities, with production ranging from Azeri gas and condensate to Brazilian heavy oil and deepwater fields in the US Gulf of Mexico (GoM). We expect to further develop our position in the gas value chain/harsh environment though our participation in Shtokman development phase 1 and in extra heavy oil through the staged development of Canadian oil sands. We will also continue to move forward our deepwater portfolio in Angola.

We also have world-class technological and project management expertise in areas such as subsea wells, drilling and completion of high-pressure, high-temperature wells, Increased Oil Recovery, gas chain management, heavy oil, gas to liquids and carbon capture and storage (CCS).

Our exploration strategy is based on gaining access to high-potential basins globally and targeting multiple blocks in high-focus areas. Our long-term ambition is to access at least one new basin for the company per year in order to support long-term growth. After securing access, the subsurface work has concentrated on preparing the acreage for drilling with a moderate risk profile at the portfolio level. We have strong strategic focus on increasing our share of operatorships with a view to shaping the future direction of our business.

Our business development activities are highly complementary to our international exploration work, working hand-in-hand to create portfolios of projects and opportunities. Our Gulf of Mexico entry strategy is a clear example of how acquisitions and exploration can build a focused portfolio with a strong inventory of projects. By making the most of our competitive advantages, we have gained access to new projects in existing and new core areas. Business development will continue to be an important tool in accessing new resources and competences.

Our strategy will support further growth through commercialising our existing technological strengths, developing new expertise and providing innovative solutions and new partnership models.

2.6.3 Key events

- Annual entitlement production grew by 31% from 2006.
- New StatoilHydro equity production capacity of approximately 40 mboe per day was added from new fields coming on stream: Q, San Jacinto and Spiderman in the US GoM and Rosa, Marimba North and Mondo (which came on stream on 1 January 2008) in Angola.
- Sanctioned projects: Peregrino heavy oil development in Brazil, Pazfloor in Angola, and the Leismer demonstration project in Canada, which is the first step in developing the oil sands acreage.
- An extensive exploration programme was executed with several significant discoveries such as Shah Deniz SDX4, Julia and West Tonga.
- Our heavy oil position was considerably strengthened by the acquisitions of North American Oil Sands Corporation in Canada, the Mariner/Bressay/Broch discoveries in the UK, and remaining share in the Peregrino development in Brazil. (The transaction is subject to government approval.) We are operator for all these projects.
- A framework agreement was signed with Gazprom to become a partner in the Shtokman development phase 1, through participation in the Shtokman Development Company.

2.7 Natural Gas

2.7.1 Introduction

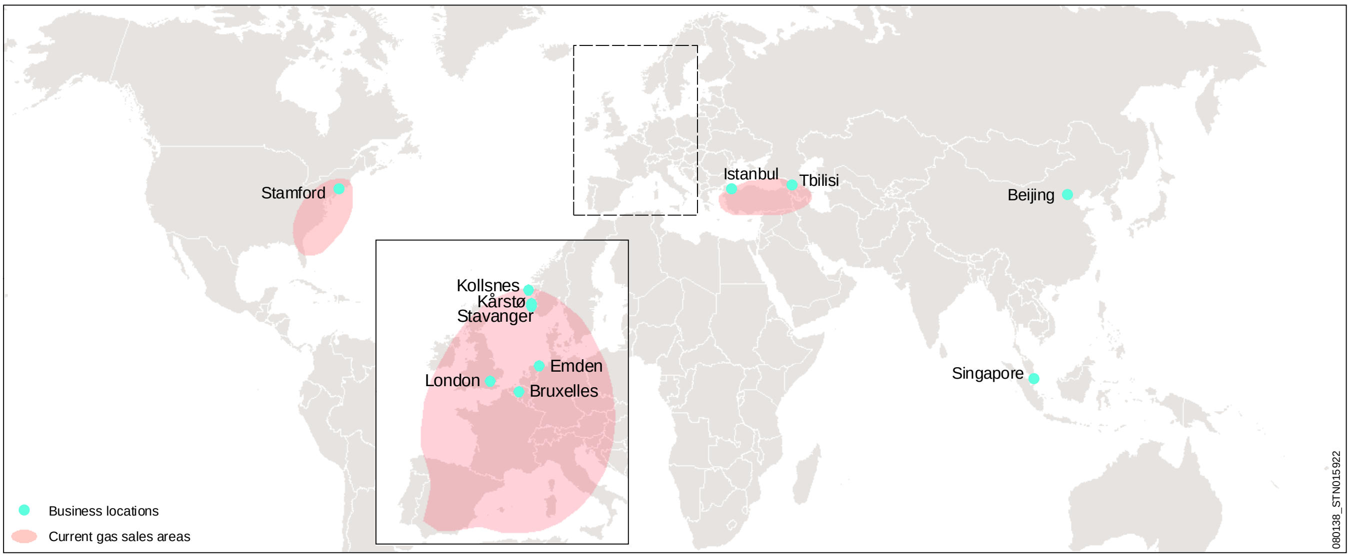
The Natural Gas (NG) business area is responsible for StatoilHydro's transportation, processing and marketing of pipeline gas and LNG worldwide, including the development of sufficient processing, transportation and storage capacity. NG is also responsible for marketing gas supplies originating from 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, China and the US.

In 2007, we sold 34.8 bcm (1.2 tcf) of natural gas from the NCS on our own behalf, in addition to approximately 31.2 bcm (1.1 tcf) NCS gas on behalf of the Norwegian State. StatoilHydro's total European gas sales, including third party gas, were 74.0 bcm (2.6 tcf) in 2007. 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 2.2 bcm (0.08 tcf) of gas in 2007, of which 0.8 bcm was entitlement gas (0.03 tcf).

We have a significant interest in the world's largest offshore gas pipeline transportation system, which is approximately 7,800 kilometres long. This network links gas fields on the NCS with gas processing plants on the Norwegian mainland and 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 are endeavouring to achieve greater efficiency from our existing supply portfolio, to deliver larger volumes and to enter into a wider range of sales arrangements in order to reach a broader customer base. Through balancing, optimisation and trading activities, we will continue to create additional value on top of our long-term sales business.

We aim to further develop our 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. The market position at the Cove Point terminal on the East Coast of the US will be further developed with equity gas supplied from the Snøhvit field and with third-party gas. In addition, natural gas is the focal point of many of the exploration and business development activities carried out by both INT and EPN. In general, 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.

The main objective of NG's strategy is to improve our growth opportunities in all parts of the natural gas business and to fully exploit the opportunities that changing market conditions provide us with. This means increased focus on extracting value from the existing contracts and asset portfolio, and on 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, 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 processing plants at Kårstø and Kollsnes, will be of key importance.

2.7.3 Key events

- First vessel with a cargo of LNG from Snøhvit.
  On 20 October 2007, the first vessel left Melkøya. For the first time we are supplying liquefied gas from the NCS by ship.
- Ormen Lange came on stream.
  Gas from the Ormen Lange field is transported from Nyhamna to Easington, in the UK through the Langeled pipeline system. At plateau, the field is expected to provide StatoilHydro with more than six billion standard cubic metres of gas per year.
- Start up of the Tampen Link pipeline.
  The pipeline opens a new corridor to the UK gas market. The Tampen Link pipeline, opened in October 2007, transports gas from the Statfjord field to the Flags transport system, which runs from the UK's Brent field to St. Fergus in Scotland.
- Regular deliveries of Shah Deniz gas to Turkey since July 2007.

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 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 2,300 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 2007, we had trading activity of 781 mmbbl of crude oil and condensate, approximately 30 million tonnes of refined oil products and 11.2 million tonnes of NGL. The refinery throughput was 15.6 million tonnes. In the energy and retail market, we sold approximately 13 billion litres in 2007, including eight billion litres of petrol and diesel.

2.8.2 Strategy

Our 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.

M&M will focus on further developing our position in North America to maximise the value creation from the group's crude production in Canada, the US GoM, and StatoilHydro production imported to North America from other regions.

Oil Sales, trading and supply

We aim to continue to strengthen our global trading position through establishing physical trading infrastructure and a presence in selected regions, based on equity production. To attract third party volumes, we also plan to evaluate infrastructure assets independently of our own equity production.

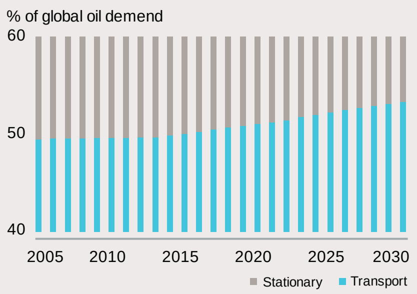
It is vital to continue to build a strong commercial organisation that is supported by flexible systems in order to succeed with increased trading activity.

Manufacturing

We expect to increase the robustness of our manufacturing facilities by further exploiting technology in order to improve reliability, optimise maintenance and increase HSE performance. M&M will focus on increasing the energy efficiency of our manufacturing facilities.

We will also endeavour to implement cost efficient and flexible liquid transportation solutions. We will seek to add value by implementing logistics solutions such as combining cargoes and crude qualities, reducing feedstock costs and providing the flexibility required to handle high acid and heavy crude oil.

THE DECLINE IN STATIONARY ENERGY*



*and increase in transportation

Energy and retail

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

Our ambition is to further develop and strengthen our downstream positions in Scandinavia and to establish StatoilHydro as a leading supplier of bio fuels in key markets. In Eastern Europe, we plan to build on our strong Baltic and Polish position, and continue to evaluate market opportunities based on the Scandinavian concept.

There will also be increased focus on expanding the downstream business in Russia, mainly based on developing a competitive retail position in the St. Petersburg area.

2.8.3 Key events

- We signed a purchase agreement with ConocoPhillips for its Scandinavian Jet brand unmanned gas station network, pending the approval of the EU Commission (20 November 2007).
- First condensate shipment from Snøhvit was received on 2 October 2007 and processed at Kalundborg.
- The carbon dioxide capture test centre Mongstad partnership was established in June 2007.
- Building of the combined heat and power plant at Mongstad started up in January 2007 and it is progressing according to schedule.
- Our energy and retail business on the Faeroe Islands was sold (19 September 2007).

2.9 Technology and New Energy

2.9.1 Introduction

Technology & New Energy (TNE) aims to be a centre of excellence for technology and new energy contributing to global business success. This means that TNE is responsible for ensuring we have 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 solutions, concept development and safe and efficient 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 into and the development, piloting, implementation and commercialisation of new technology. The new energy department is responsible for developing a sustainable business for new energy, comprising development projects and technology development such as wind power, bio fuels, hydrogen and carbon capture and storage.

2.9.2 Strategy

TNE is an important partner for the business areas and is responsible for research and development and new energy.

Technology strategy

The technology strategy continues to be upstream-focused, although considerable attention is also paid to integrating technology into value chains, the exploitation of oil sands, carbon management and renewable energy sources. In addition to advancing a range of technologies, we aim to develop and/or sustain distinctive technology positions in selected areas in order to optimise ongoing operations, achieve competitive advantages and build new platforms for growth.

To replace resources, we plan to develop technologies that are specifically designed to rapidly identify and acquire prime exploration acreage and production assets and improve recovery factors, especially from complex reservoirs. We also plan to develop technology aimed at successfully exploiting our widening portfolio of international ventures, which now includes tight reservoirs and heavy oil. For example, through the acquisition of NAOSC in 2007, we have become heavily involved in the Canadian oil sands business in which the main challenges are to improve recovery and meet demanding environmental standards throughout the value chain.

Customised technologies and capabilities are also required to address frontier area challenges, which in some cases differ radically from those encountered on the NCS. Today, they are largely related to deepwater and harsh environments. Furthermore, our gradual transition from topside to seabed facilities, when coupled with long-distance multiphase transport and pressure boosting, will facilitate ultra-deepwater field developments and pave the way for Arctic operations.

Supplier cooperation and venture activities are expected to 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.

New Energy

Our New Energy business aims to achieve profitable growth in the sale of wind power and bio fuels. For wind power, there are short-term opportunities in land-based and near-shore developments. In the longer term, the development of technology for offshore wind power may pave the way for the supply of renewable power on a large scale. In bio fuels, the main focus is on traditional (first generation) bio diesel and bio-ethanol, with the emphasis on documented sustainable production. In the longer term, synthetic (second/third generation) products and processes are being investigated.

Furthermore, we intend to sustain our position as a leading industry player in carbon capture and storage. Building on the Kyoto mechanisms (e.g. the Clean Development Mechanism), we intend to reap the benefits of our carbon dioxide expertise. We are also exploring the potential of hydrogen and other renewable energy technologies as additional areas for long-term, profitable growth.

2.9.3 Key events

Technology

- Managed depleted reservoir drilling in the high-pressure, high-temperature Kristin field.
- We developed and delivered the world's longest multiphase flow pipelines on the Ormen Lange (120 km) and Snøhvit (143 km) gas fields.
- Put into use a remote-controlled subsea dredger - Nexans Spider - to prepare the seabed at Ormen Lange for pipe installation.
- In 2007, we delivered the world's longest subsea pipeline, Langeled, carrying Ormen Lange gas from central Norway to the UK over a distance of 1,200 kilometres.
- In 2007, we delivered the world's first commercial subsea separation, boosting and injection system on the Tordis field.
- Reaming has been carried out on the Grane field to install screens and complete a well penetrating unstable shale in reservoir intervals.
- High resolution seismic data obtained using shallow gun and cable tow depths reveal that captured carbon dioxide stored in the Utsira Formation (Sleipner field) does not appear to be leaking into the overlying shales.

New Energy

- Opening of Mestilla bio fuels production plant in Lithuania.
- Hywind (floating windmill) demo project received support from Enova.
- The carbon dioxide test centre Mongstad partnership was established.

2.10 Projects

2.10.1 Introduction

Projects (PRO) is responsible for planning and executing all development and modification projects costing more than NOK 50 million, as well as for contributing to safe and efficient operations in connection with those projects. Projects is also responsible for procurement, including securing rig capacity based on a corporate rig strategy.

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

Our current portfolio consists of more than 80 modification and development projects in the execution phase, with a total expected investment cost of more than NOK 150 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 projects on time, at cost and in a safe and reliable manner.

Our ability to utilise the company's world-leading technology and execute projects in complex surroundings will be of vital importance in terms of opening up new business opportunities, as will our ability to demonstrate our core expertise in new markets.

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.

We are constantly encountering new and complex markets, and are facing increased global demand for resources due to an extremely high activity level in the oil and gas industry. This is a challenge for international project execution due to the impact it has on price levels, availability, quality and lead times for deliveries.

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, a number of fields will need upgrading or renewal of drilling units, control systems, hydrocarbon processing systems, cranes and other major redevelopment efforts.

In order to handle this 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. We aim for diversity among our suppliers, and are continuously on the lookout for innovative solutions and for suppliers that can offer us the best product, the best technology and the best quality.

Our procurement function works to ensure that we have the rig capacity required to drill both new prospects and production wells.

2.10.3 Key events

- The Alve Plan for Development and Operation (PDO) was approved by the Norwegian government in March 2007.
- The Ormen Lange/Langeled field development was completed on schedule. On 30 November 2007, the operatorship of the large Ormen Lange field was formally transferred to Shell.
- PDOs for the Gjøa and Vega fields were approved in June 2007. The Gjøa field will be developed with several subsea production systems tied back to a semi-submersible platform for processing and export. The Vega field will also be tied back to the Gjøa semi-platform.
- The acquisition of the North American Oil Sands Corporation was completed in June. In August, the authorities in Alberta granted approval for the development of the Leismer SAGD Demonstration Project.
- Production from the Huldra field was restarted in June after installation of a new compressor module that enables low pressure gas production.
- Production drilling on the Volve field was started in June, and ordinary production from the field started in mid-February 2008.
- The Kårstø expansion project (KEP 2010), which is expected to cost more than NOK 6 billion, was sanctioned.
- Rig capacity was secured for the planned activity level in 2008.

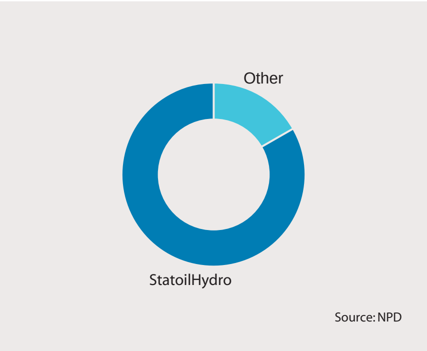
3 Operational review

3.1 E&P Norway

3.1.1 Industry overview

Total production from the NCS is at a historically high level. In 2007, the total production from the NCS was 4.1 mmboe per day. However, production of oil on the NCS has decreased since peaking in 2001 and it is now at the lowest level since 1993/94. While oil production on the NCS shows a falling trend, natural gas production is increasing and we expect production of natural gas will constitute a larger share of total production in the future. This will affect both the level of activity and profitability on the NCS.

NCS OPERATED PRODUCTION



Increased oil recovery from the existing fields is an important factor in maintaining the current production level. Most of the IOR measures are related to the drilling of new wells. Securing rig capacity is vital in terms of increasing the recovery factor. This has been a major challenge for the industry and, combined with a tight supply market, it has led to an upward pressure on rig rental expenses.

Another challenge facing the companies on the NCS is that future production will come from smaller and more complicated fields. The new development projects have more complex reservoirs and are technically more challenging. They will therefore demand more resources per barrel than the older and larger fields.

We believe there is still 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.

Access to attractive acreage is an important factor in realising the potential of the NCS. In January 2008, 37 companies were awarded 52 new licenses in the North Sea, the Norwegian Sea and the Barents Sea relating to APA 2007 (Awards in Predefined Areas). The annual APA concession system offers relinquished acreage and un-awarded 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 infrastructures are available for the industry. The APA area will be expanded as new exploration areas are matured.

The Norwegian authorities decided to postpone the 20th Licensing Round until 2009 in order to ensure cost-efficient exploration of frontier areas on the NCS according to a press release from the Norwegian Petroleum Directorate.

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

3.1.2 The NCS portfolio

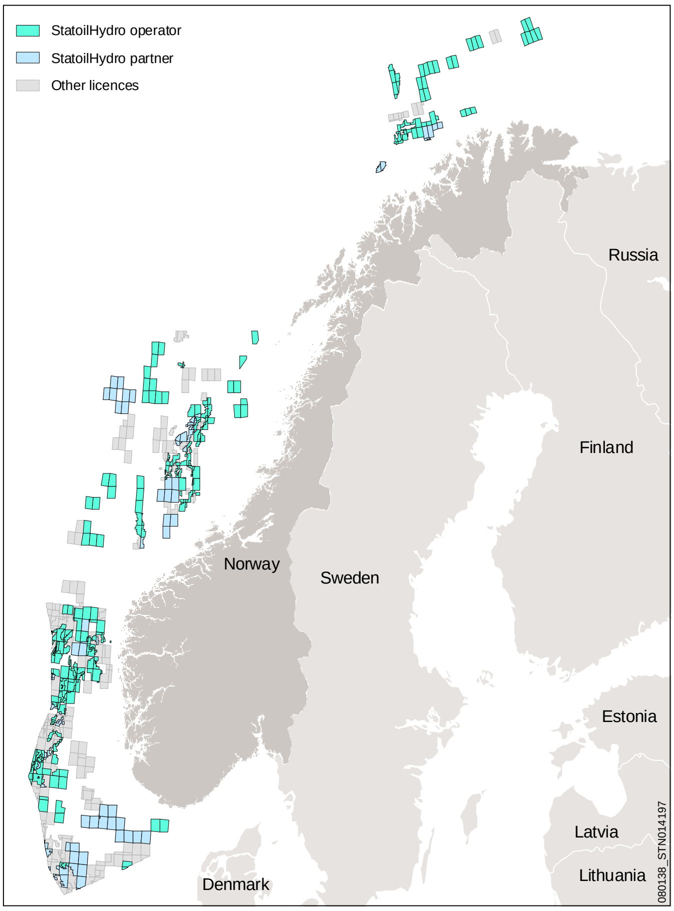
3.1.2.1 Core production areas

Our 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 considerable number of exploration licences. The exploration acreage is located in both undeveloped frontier areas and close to infrastructure and producing fields.



North Sea. Total licensed acreage in the North Sea covers 66,548 square kilometres. We participate in 33,241 square kilometres and operate 20,086 square kilometres. Following execution of the work programme and prospectivity evaluation, a decision was made to relinquish five licenses and farm-out two licenses in 2007. Four licenses were awarded to us in the awards in predefined areas (APA) 2007 and we became operator of three of these.

Norwegian Sea. Total licensed acreage in the Norwegian Sea covers 41,815 square kilometres. We participate in 27,139 square kilometres and operate 18,736 square kilometres. In the deepwater region we have interests in licenses covering approximately 16,000 square kilometres. Following execution of work programme and prospectivity evaluation, five licenses were relinquished in the Norwegian Sea in 2007, two in the deep water region and three in the shallow water region. Four licenses were awarded to us in the APA 2007, and we became operator of all of these. The Nordland VI & VII and Troms II area outside Lofoten and Vesterålen is temporarily closed for petroleum activity due to environmental concerns. The Norwegian parliament will evaluate opening of this area in 2010.

Barents Sea. Total licensed acreage in the Barents Sea covers 13,421 square kilometres. We participate in 11,460 square kilometres and operate 10,052 square kilometres. Following execution of the work programme and prospectivity evaluation, two licenses were relinquished in 2007. In addition, we have relinquished 5,300 square kilometres of the 13,500 square kilometres of seismic option areas. Four licenses were awarded to us in the APA 2007, and we became operator of two of these. We also became operator of one additional award from the APA 2006.

3.1.2.3 Portfolio management

We use portfolio management as an active tool to optimise our license portfolio, strengthen our core areas and achieve our long term production targets. Statoil's share in Murchison (11.52% in the Unit) was sold in June, and Trym(30%)was sold in July 2007. Other transactions were related to exploration licences.

3.1.3 Exploration

In 2007, we participated in 24 exploration wells, 16 of which resulted in discoveries. We operated 19 of the 24 exploration wells, including 14 of the 16 discoveries. In addition, we operated two exploration extensions, both of which resulted in discoveries.

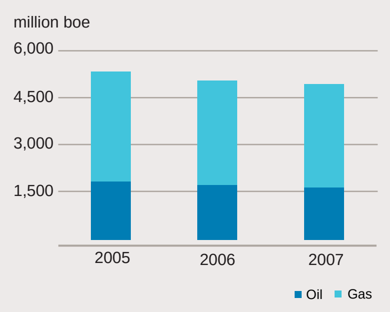
In 2007, the most important discoveries in the North Sea were Ermintrude and Ragnarrock, both close to the Sleipner field. In the Oseberg area, production tests carried out on the Shetland Chalk oil discovery confirmed recoverable resources in chalk reservoirs. In the shallow water of the Norwegian Sea, the Onyx South West gas discovery increased the probability of a new gas province development. In the Barents Sea, the Goliat West well proved additional resources in deeper segments, and the Nucula discovery confirmed the oil potential in this part of the Barents Sea.

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

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

3.1.4 Oil and gas reserves

OIL AND GAS RESERVES



As of the end of 2007, we had a total of 1,604 mmbbl of proved oil reserves and 535 bcm (18.9 tcf) of proved natural gas reserves on the NCS. Measured in barrels of oil equivalent (boe), our proved reserves consist of 32% oil and 68% natural gas, based on total proved reserves on the NCS of 4,971 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 2007 that would mean a significant change in the estimated proved reserves as of that date. Further information on reserves can be found in note 32 - Supplementary oil and gas information - to our Consolidated Financial Statements. .

Year		Oil/NGL mmbbls	Natural gas bcm	bcf	Total mmboe
2007	Proved reserves end of year	**1,604**	**535.2**	**18,893**	**4,971**
	of which, proved developed reserves	**1,187**	**427.3**	**15,084**	**3,875**
2006	Proved reserves end of year	1,667	541.5	19,129	5,068
	of which, proved developed reserves	1,188	378.6	13,378	3,566
2005	Proved reserves end of year	1,835	554.6	19,595	5,316
	of which, proved developed reserves	1,363	393.4	13,899	3,833

3.1.5 Production

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 [1]	Operator	On stream	License expiry date	Producing wells Oil	Producing wells Gas	Average daily production in 2007 mboe/day
Sleipner Øst	59.60%	StatoilHydro	1993	2014		18	**53.4**
Sleipner Vest	58.35%	StatoilHydro	1996	2014		18	**110.5**
Gungne	62.00%	StatoilHydro	1996	2014		4	**16.3**
Troll Phase 1 (Gas)	30.58%	StatoilHydro	1996	2030		39	**191.2**
Troll Phase 2 (Oil)	30.58%	StatoilHydro	1995	2030	113		**50.4**
Fram	45.00%	StatoilHydro	2003	2024	7		**20.1**
Kvitebjørn	58.55%	StatoilHydro	2004	2031		4	**10.7**
Visund	53.20%	StatoilHydro	1999	2023	5	1	**36.5**
Grane	38.00%	StatoilHydro	2003	2030	22		**78.8**
Veslefrikk	18.00%	StatoilHydro	1989	2015	18		**2.9**
Huldra	19.88%	StatoilHydro	2001	2015		5	**3.4**
Glitne	58.90%	StatoilHydro	2001	2013	7		**4.7**
Heimdal	29.87%	StatoilHydro	1985	2021 [2]		6	**1.0**
Brage	32.70%	StatoilHydro	1993	2017 [3]	22		**8.1**
Vale	28.85%	StatoilHydro	2002	2021		1	**1.6**
Total Operation North Sea					194	96	**589.5**
Statfjord Unit	44.34%	StatoilHydro	1979	2026	89	1	**62.4**
Statfjord Nord	21.88%	StatoilHydro	1995	2026	8		**4.7**
Statfjord Øst	31.69%	StatoilHydro	1994	2026 [4]	8		**9.0**
Sygna	30.71%	StatoilHydro	2000	2026 [5]	3		**2.0**
Gullfaks	70.00%	StatoilHydro	1986	2016	113	4	**168.6**
Snorre	33.32%	StatoilHydro	1992	2024 [6]	38		**49.4**
Tordis area	41.50%	StatoilHydro	1994	2024	9		**18.4**
Vigdis area	41.50%	StatoilHydro	1997	2024	8		**26.6**
Gimle	65.13%	StatoilHydro	2006		1		**6.3**
Oseberg	49.30%	StatoilHydro	1988	2031	44		**99.3**
Tune	50.00%	StatoilHydro	2002	2032		4	**17.4**
Total Operations West					321	9	**464.0**
Kristin [7]	55.30 %	StatoilHydro	2005	2033 [8]	10		**87.1**
Norne [9]		StatoilHydro			14		**42.7**
Heidrun	12.41%	StatoilHydro	1995	2024	35		**15.3**
Åsgard	34.57%	StatoilHydro	1999	2027	23	7	**127.0**
Mikkel	43.97%	StatoilHydro	2003	2022 [10]		3	**25.5**
Njord	20.00%	StatoilHydro	1997	2024 [11]	7		**4.0**
Snøhvit	33.53%	StatoilHydro	2007	2035		6	**1.3**
Total Operations North					89	16	**302.9**
Ormen Lange	28.92%	Shell	2007	2041		3	**8.6**
Ekofisk area	7.60%	ConocoPhillips	1971	2028	141		***25.9***
Ringhorne Øst	14.82%	ExxonMobil	2006	2030	3		**4.2**
Sigyn	60.00%	ExxonMobil	2002	2018	1	2	**17.8**
Enoch	11.78%	Talisman	2007	2013	1		**0.7**
Skirne	10.00%	Total	2004	2025		2	**2.3**
Murchison (Norwegian Part)	11.52%	CNR	1980	2009	15		**0.7**
Total Partner operated fields					161	7	**60.1**
Total					765.0	128.0	**1,416.5**

(1) Equity interest as at 31 December 2007.

(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) PL 134B expires in 2027 and PL199 expires in 2033.

(9) Norne's equity equals to 39.1%, and the field came on stream in 1997. License expiry date is 2026.
Urd's equity equals to 63.95%, and the field came on stream in 2005. License expiry date is 2026.

(10) PL092 expires in 2020 and PL121 expires in 2022.

(11) PL107 expires in 2021 and PL132 expires in 2024.

In 2007, our total equity oil production in Norway was 298.5 mmbbl, and gas production was 34.7 bcm (1,227 mmcf), which represents an aggregate of 1.417 mmboe per day. Our producing fields are currently organised into four business clusters: Operations West, Operations North Sea, Operation North and Partner Operated Fields.

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 2007 and 2006.

	For the year ended 31 December					
	2007			2006		
Area production	Oil and NGL mbbl	Natural gas mmcm	mboe	Oil and NGL mbbl	Natural gas mmcm	mboe
Operations North	**181**	**19**	**303**	182	16	281
Operations North Sea	**236**	**56**	**590**	262	59	634
Operations West	**362**	**16**	**464**	379	20	503
Partner operated fields	**39**	**3**	**60**	41	2	56
Total	**818**	**95**	**1,417**	864	97	1,474

3.1.6 Development

3.1.6.1 Fields under development

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. As of 31 December 2007, NOK 0.8 billion had been invested. The total investment for the project is estimated to be NOK 2.5 billion.

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. We have a 49.3% ownership interest in the project. Investments in the project are estimated to amount to NOK 2.3 billion. NOK 1.5 billion had been invested as of 31 December 2007. Production is scheduled to start in early 2008.

Gjøa 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 29.7 billion and, as of 31 December 2007 NOK 4.2 billion had been invested. We hold a 20% interest in Gjøa. Production is scheduled to start in late 2010.

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. 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. As of 31 December 2007, NOK 0.7 billion had been invested. Production is scheduled to start in late 2010.

The **Vilje** project comprises the development of two oil wells in the Vilje reservoir (PL036). Two satellite wells have been installed, and production from the field will be transported to the Alvheim FPSO (Marathon operated) in a 19 km pipeline. A parallel gas pipeline feeds Vilje with downhole lift gas from Alvheim. As of 31 December 2007, NOK 2.4 billion had been invested. The total investments for the project are estimated to be NOK 2.5 billion, including investments of NOK 0.8 billion on Alvheim. The date for production start-up will depend on the schedule for the FPSO, and it is estimated to be mid-2008.

Tyrihans, in which we hold an interest of 58.5%, is located in the Norwegian Sea and consists of two hydrocarbon accumulations: the 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. 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 14.5 billion, with NOK 5.1 billion having been invested as of 31 December 2007.

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. The field will be a subsea development with two templates tied in to Åsgard B for processing through a 20 km long wellstream pipeline. The development of Morvin is currently estimated to require capital expenditure of NOK 8.7 billion, and production from the field is estimated to commence in late 2010. As of 31 December 2007, NOK 0.5 billion had been invested.

The **Yttergryta** subsea gas and condensate field development, with an investment value of approximately NOK 1.2 billion, is an excellent example of a relatively small but unique project in our portfolio. The discovery was made in the summer of 2007 and the PDO was submitted in January 2008. Production start-up is expected to take place in early 2009. As of 31 December 2007, NOK 0.2 billion had been invested. We hold a 45.75% interest in the project.

The world's largest drilling rig for Arctic areas, Aker Spitsbergen, is expected to commence production drilling on Yttergryta during the summer of 2008, and the wellstream will be tied back to the Åsgard B platform for processing and further export.

Gulltopp. A long-reach well is being 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 estimated start-up of production is mid-2008.

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. It is located in the Norwegian Sea. We have an interest of 36.165%. BP is the operator. Skarv extends across three production licences (PL212/262 Skarv and PL 159 Idun). The field is being developed by 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. At the time the PDO was submitted, the total development cost was estimated by the operator to be NOK 32 billion.

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%	2.1	2009	21,000	12
Gjøa	20.000%	5.9	2010	19,000	15
Morvin	64.000%	5.6	2010	21,000	14
Oseberg Delta	49.300%	1.1	2008	15,000	18
Skarv [2]	36.165%	11.7	2011	53,000	12
Statfjord Late Life	44.340%	8.4	2007	43,000 [3]	12
Tyrihans	58.840%	8.5	2009	56,000	17
Vega/Vega Sør	60%/45%	4.3	2010	30,000	13
Vilje	28.853%	0.7	2008	8,000	15
Yttergryta	45.750%	0.5	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 **Statfjord Late Life (SFLL)** project will convert Statfjord into a mainly gas producing field by changing the drainage strategy. The 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 18.9 billion, including the pipeline investment of NOK 1.8 billion. As of 31 December 2007, NOK 8.6 billion had been invested.

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 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.

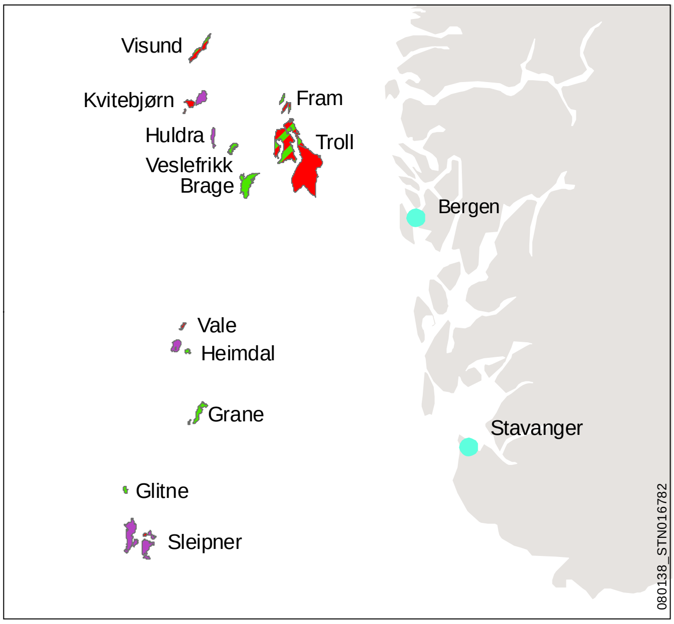
A new **low-pressure compressor module on Troll C** will be installed to increase capacity, and thereby production and recovery from Troll Vest.

A major modification is currently being carried out on the **Sleipner B wellhead platform**, where pre-compression facilities will be installed in order to boost gas production through reduced wellhead pressure. Start-up is planned in late 2008.

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 most of StatoilHydro's production activity in the North Sea. Our producing fields in Operations North Sea are Troll, Fram, Sleipner, Kvitebjørn, Visund, Grane, Brage, Veslefrikk, Huldra, Glitne, Volve, Heimdal and Vale. The area is dominated by the production of natural gas, as 60% of the equity production 2007 was gas. The petroleum reserves are located under water depths of between 80 and 330 metres. There is high focus on increasing and prolonging production in the area. Increased oil recovery and the exploration and development of new fields have priority. In late 2007, our application for an extension of the licence period in the Sleipner area until 2028 was approved, which is expected to have a positive impact on the economic life of the infrastructure in the area.

In 2007, StatoilHydro's share of the area's production was 236 mbbl of oil, condensate and NGL per day and 56 mmcm (1,984 mmcf) of gas per day, or 590 mboe in total per day. In October 2007, the 1,200 kilometre long Langeled pipeline, the world's longest subsea gas pipeline, began carrying gas from the processing plant at Nyhamna, via Sleipner to Easington in England.

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 Future Development Project involving a planned capacity increase on Troll A and Kollsnes was discontinued due to the decision by the Norwegian Ministry of Petroleum and Energy not to increase the production permit beyond the current level. . The building blocks that were not affected by the government decision are continued through the Troll Project, for which a PDO is expected to be submitted in 2008.

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

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 underneath the seabed to reduce the carbon dioxide emissions into the air. In 2007, the Sleipner field, including Volve, was granted an extension of its permit by the Ministry of Petroleum and Energy, which will enable the field to operate until 2028. We are currently exploring several prospects and discoveries in the Sleipner area that can potentially be tied in to Sleipner.

In 2006, StatoilHydro and the licensees decided to reduce gas and oil production temporarily from **Kvitebjørn** in order to ensure sound reservoir management and safe drilling operations. Production was stopped in May 2007 in order to finish two wells. A successful utilisation of the Kvitebjørn Managed Pressure Drilling concept made it possible to finish these two wells. A routine inspection in autumn 2007 revealed that the gas pipeline from Kvitebjørn to the Kollsnes gas plant had been shifted out of position by a ship's anchor. The pipeline's weight coating sustained external damage. The pipeline was shut down for further examination.

Consequently, the start-up of production on Kvitebjørn was postponed. Kvitebjørn resumed production in January 2008 after examinations showed that the pipeline could be used temporarily for export. The pipeline repairs are weather dependent and are therefore scheduled for the summer season 2008. Gas and condensate exports from Kvitebjørn will be halted during the repair period.

Gas exports from Visund, which uses the pipeline, were also affected by the pipeline damage.

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.

Grane is an oilfield 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. In 2007, three new wells were completed using new technology, which was tested on Grane.

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 (OTS) to the Sture terminal. A gas pipeline is tied back to Statpipe.

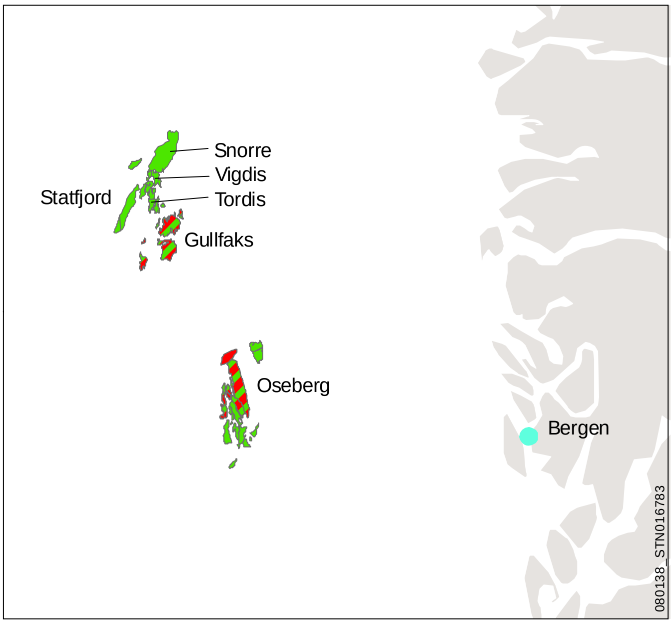
Veslefrikk is an oilfield located north of Oseberg in the northern part of the North Sea. **Huldra** is located in the Viking Graben and developed by a (normally unmanned) platform, remotely controlled from the Veslefrikk field. Oil from Veslefrikk is exported through the Oseberg Transportation System,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

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.

Volve is an oilfield located in the southern part of the North Sea approximately eight kilometres north of Sleipner East. The development is based on production from the Mærsk Inspirer jack-up rig, with Navion Saga 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.

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.

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 2007 was 362 mbbl per day of oil, condensate and NGL, and 16 mmcm per day (575 mmcf per day) of gas, or 464 mboe per day in total. Operations West is the leading oil producing area on the NCS and, even after twenty 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 increased oil recovery, and they have resulted in a prolongation of planned production beyond the current licence period for several of the fields.

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 North, Statfjord East and Sygna) have been developed, each of them tied back to the Statfjord C platform. In 2005, an amended PDO was approved by the 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. In 2009, the three Statfjord platforms are scheduled for conversion to produce oil and gas with a lower reservoir pressure.

During oil offloading from the Statfjord A platform on 12 December 2007, about 4,400 standard cubic metres of crude oil were spilled into the sea.

Statfjord B celebrated 25 years of production in November 2007.

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. Three satellite fields, Gullfaks South, Rimfaks and Gullveig, have been developed with subsea wells remotely controlled from the Gullfaks A and C platforms.

The **Gimle** field is a Gullfaks satellite field. 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 2007, Gimle consisted of one producer and one injector, and drilling of a new producer will start early 2008.

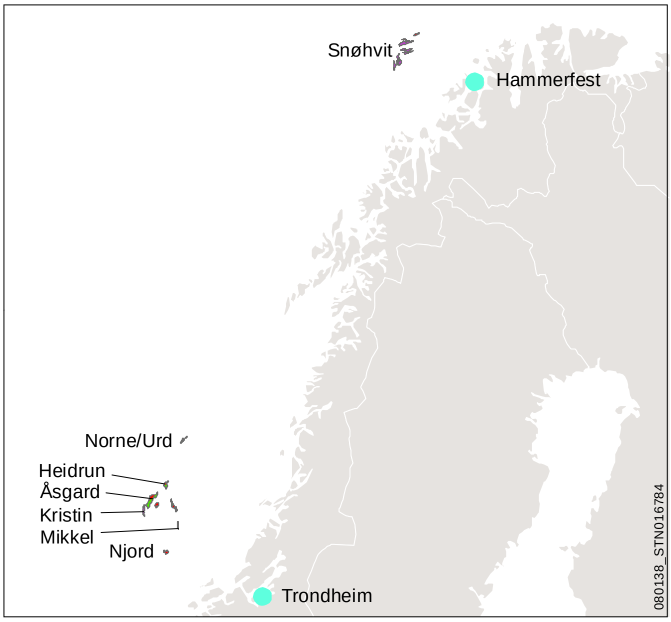
The **Oseberg** area includes the main Oseberg field developed with Field Centre installations and the Oseberg C production platform, and two satellite fields, Oseberg East and Oseberg South, developed with production platforms. In addition, the Tune field and Oseberg West Flank have been developed with 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.

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. The Snorre field celebrated 15 years of production in 2007.

The **PL 089** asset includes the Vigdis field and the fields in the Tordis Area. The Tordis area has 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 was installed on Tordis in 2007.

The Vigdis reservoir 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 Vigdis Extension Phase 2 project will be completed by early 2008.

3.1.7.3 Operations North



Our producing fields in the Operations North area are Åsgard, Mikkel, Heidrun, Kristin, Norne, Urd, Njord and Snøhvit. Our share of the area's production in 2007 was 181 mbbl per day of oil, condensate and NGL, and 19 mmcm per day (686 mmcf per day) of gas, or 303 mboe in total per day.

This region is characterised by petroleum reserves located at water depths between 250 and 500 meters. 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 **Åsgard** field contains three fields: Smørbukk, Smørbukk South and Midgard. The field complex 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 in the field complex 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.

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 pipeline to gas markets in continental Europe.

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.

The **Urd fields**, Svale and Stær, are located 10 km and 5 km north of the Norne field, respectively. The fields are produced through subsea facilities with the well stream tied back to the Norne FPSO. Production from the first two Urd wells started in the fourth quarter of 2005.

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.

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 bars 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 2007, the last of twelve wells was completed and entered into production.

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 on the surface.

The natural gas is transported to shore through a 143 kilometre long pipeline and it is landed at Melkøya, where it is processed. Snøhvit 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 uncertainties related to the timing of regular and stable operations. See also Risk review-Risk factors-Risks related to our business about uncertainties with and operating risks related to development projects.

3.1.7.4 Partner operated fields

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 on 1 December 2007. StatoilHydro will continue 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. Production started in September 2007.

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 operating field complex in our portfolio. It is operated by ConocoPhillips. The ownership interest is 7.60%. The Ekofisk Area Growth project is ongoing, including several sub-projects, such as Eldfisk II, Ekofisk South and a new accommodation platform for the Ekofisk Centre. Alternatives are being evaluated for improving resource management on the Ekofisk, Eldfisk and Tor fields.

StatoilHydro has a 14.82% interest in the ExxonMobil-operated field **Ringhorne East**. It is located within PL 027 and PL 169 in the North Sea. 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

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. There has been no decommissioning of StatoilHydro-operated fields during the last three years. On partner-operated fields there has been removal activity on Frigg and Ekofisk.

3.2 International E&P

3.2.1 Industry overview

A number of fundamental changes have taken place in the international oil and gas industry over the past few years. These are likely to result in continued strong competition for upstream opportunities.

The strong rise in commodity prices has led to increased activity in the industry. This, combined with supplier bottlenecks, has contributed to increased costs.

These changes have taken place at a time when the industry has been attracting a much higher level of competition, both in terms of the number and type of participants and the complexity of projects. Politics and new policies continue to influence the environment in resource-rich countries across the world. In general, the more resources a country has in the ground, the stricter the fiscal terms for participants. Conventional OECD resources represent a relatively minor part of discovered global oil and gas resources.

The increased complexity of new projects is resulting in higher risk and capital expenditure. Moreover, unconventional reserves will also require further downstream capital expenditure (e.g. upgraders) than conventional additions to reserves have historically required.

3.2.2 Portfolio management

In November 2006, StatoilHydro and Anadarko Petroleum Corporation signed an agreement under which StatoilHydro agreed to acquire two of Anadarko's US Gulf of Mexico discoveries and one prospect for USD 901 million. The transaction was completed in the first quarter of 2007.

In June 2007, we agreed with the Venezuelan government on the main terms and conditions for our participation in the new incorporated joint venture to be created for the Sincor project. The new mixed company, PetroCedeño S.A., started on 9 February 2008. At year end 2007, StatoilHydro held a 15% share in the Sincor project, while our new share in PetroCedeño S.A. is 9.677%

In June 2007, we acquired 100% of the shares in NAOSC for approximately USD 2.0 billion. Through the acquisition, we gained access to 275,213 net acres of oil sands leases located in the Athabasca region of Alberta, Canada.

In August 2007, we acquired the discoveries Mariner (44.44%), Mariner East (62.0%) and an additional 65.63% equity in Bressay (our interest is 81.63%) on the UK continental shelf (UKCS) from Chevron. In the same UK area we also acquired a 30% interest in the discovery Broch from the Canadian companies Silverstone and Wilderness. These are all heavy oil discoveries and StatoilHydro is the operator of all these licences.

In October 2007, we signed a framework agreement with Gazprom to become a partner in the Shtokman development, phase 1. The agreement gives us a 24% equity interest in Shtokman Development Company, in which Gazprom and Total are the two other partners. The project planning phase aims to establish an acceptable technical and commercial basis for the final investment decision, which is expected to be made in the second half of 2009. Until the final investment decision is made, our exposure is limited to the company's share of the costs of planning and studies.

In December 2007, we entered into an agreement to sell all the former Spinnaker assets in the shallow water of the US Gulf of Mexico to Mariner Energy, Inc. for a cash consideration of USD 243 million. The transaction was accomplished through the sale of our wholly owned subsidiary Hydro Gulf of Mexico, LLC. The sale was effective 1 January 2008.

In December 2007, we signed a sales and purchase agreement with Fairfield & Mitsubishi to divest our interests in both the Dunlin (28.76% interest) and Merlin (2.35% interest) fields on the UKCS. The sale was effective from 1 January 2008 and is expected to be completed in April 2008.

In March 2008, we signed an agreement with Anadarko to take over the remaining 50% in the Brazilian Peregrino project. This will give us a 100% working interest and operatorship of the development. In addition, we are acquiring Anadarko's 25% interest in the Kaskida discovery in the deepwater US Gulf of Mexico. The transaction is subject to government approval and the acquisition of the Kaskida discovery is also subject to other parties not exercising preferential rights to purchase. As of 4 April, the company has been formally notified that two of such parties intend to exercise their preferential rights to purchase which, if exercised, will result in the company not acquiring an interest in the Kaskida discovery, but will not affect the company's interest in Peregrino.

3.2.3 Exploration activity

The exploration strategy for StatoilHydro was revised in 2002**,** and we carried out a major global screening of oil and gas basins to rebuild our exploration portfolio. Progress from 2002 to date has been very positive. We have added significant resources and targeted new high-potential basins globally. As we have matured existing and acquired blocks, we have seen a considerable step-up in both number of wells drilled and resources discovered.

We completed 47 wells in 2007 and 11 were ongoing as per year end. Of 47 wells, 18 were announced as discoveries and 14 were under evaluation at year end. All of the 11 ongoing wells have been completed in the first quarter 2008, and two of these have been announced as discovery.

We are further high-grading prospects for our short-term drilling, which imply prioritisation and sequencing of the most prospective drilling targets, more optimal allocation of rig fleet and a dedicated exploration organisation to exploit the overall competence pool of StatoilHydro internationally. We plan to drill about 35 wells in 2008.

The areas where we entered or had significant activity in 2007 are covered below. In addition, we have licences in Cuba, Morocco, Mozambique, the Faeroe Isles, Ireland, Denmark and Iran.

3.2.3.1 North America

3.2.3.1.1 Canada

Through a land sale in 2006, StatoilHydro was awarded operatorship for a 50% interest in two licences, EL 1100 and EL1101, in the southern part of the Jeanne d'Arc Basin near the Terra Nova Field.

In 2008, we have planned the acquisition of 3D seismic data for EL 1100 and EL1101. Evaluations of existing licences will aim to identify new drillable prospects.

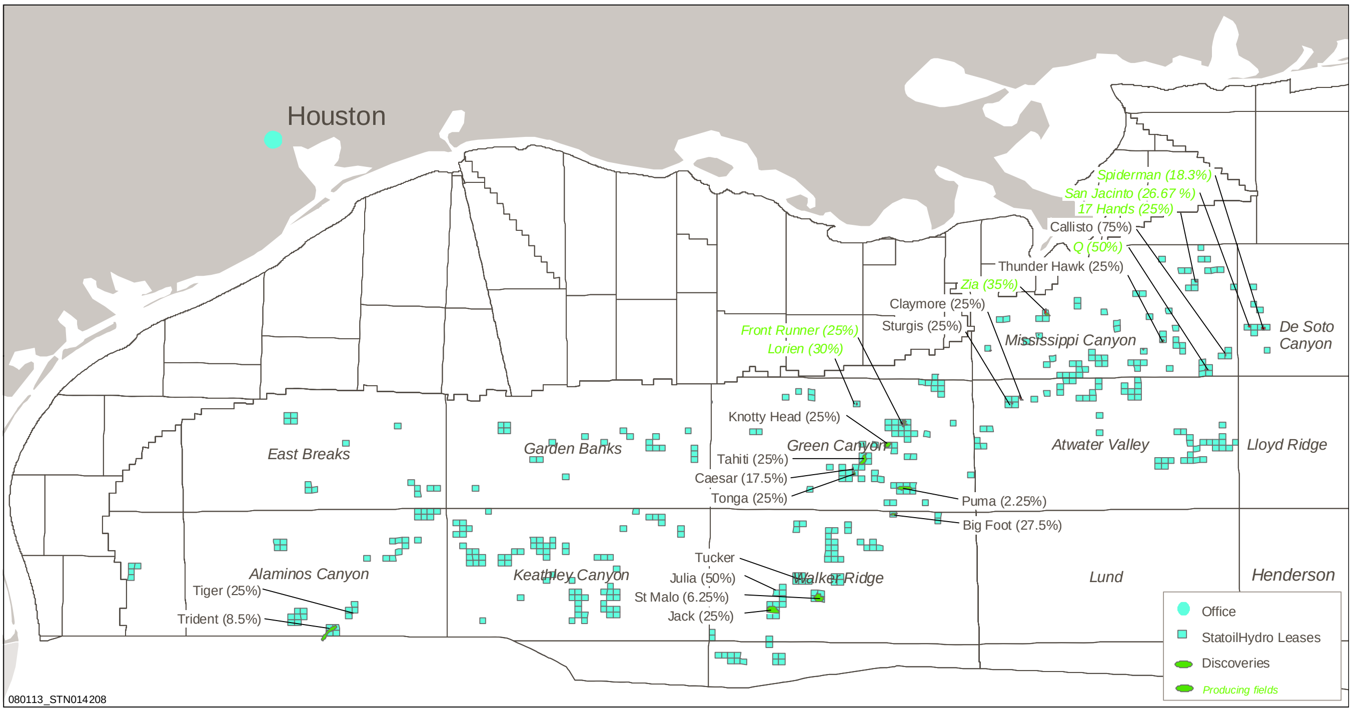
One exploration well was completed in early 2007 to test the hydrocarbon potential of a structure southeast of the Terra Nova Field. The well, operated by Petro Canada, encountered oil and has been suspended without being production tested.

A 3D seismic survey of 520 square kilometres was acquired in 2007 on EL1092 near the Hibernia field in the Jeanne d'Arc Basin. We have a 50% interest in this Petro Canada-operated licence.

3.2.3.1.2 The USA

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 US Gulf of Mexico. Our current deepwater GoM portfolio consists of more than four hundred leases. acquired through the 2005 acquisitions of the EnCana and Spinnaker Gulf of Mexico portfolios, combined with a number of exploration led farm-in agreements (e.g. Chevron in Alaminos Canyon and ExxonMobil in Walker Ridge) and lease sale awards.



In 2006, we acquired Plains Exploration & Production's working interest in two US GoM deepwater discoveries (Caesar and Big Foot) and one prospect (Big Foot North), as well as Anadarko's interest in two discoveries (Knotty Head and Big Foot) and the prospect Big Foot North.

During 2007, we completed four exploration wells, four appraisal wells and one sidetrack in deep waters. Two exploration wells, one appraisal well and one appraisal sidetrack were still operating at year end. The Julia and Tonga West wells were announced as deepwater discoveries in 2007. Appraisal well Big Foot 3, sidetrack number two, has confirmed the same pay intervals of the previously announced discovery and sidetrack well.

In addition, during 2007, we participated in five exploration wells and one appraisal well on the shelf, two of which resulted in discoveries.

We participated in both the Western and the Central lease sales held in 2007. Following the Western sale we were awarded 42 deepwater leases covering five prospects in our Paleogene focus area. We were awarded 21 deepwater blocks in the Central lease sale 205 in the first quarter of 2008. In addition we were the highest bidder on 16 leases in the Central area lease sale 206 announced on 19 March 2008. The winning bids are subject to review and final approval by the Minerals Management Service (MMS), which can take up to 90 days. There are no work commitments associated with Gulf of Mexico leases.

In 2007, we sold 18 deepwater blocks to Cobalt International Energy. We also farmed out our 35% equity share in Green Bay to Anadarko in return for the rig which Anadarko brought in to drill the first Green Bay well.

The completion of the North Bront exploration well resulted in StatoilHydro earning 50% of ExxonMobil's equity in their Alaminos Canyon leases.

All our assets on the Shelf were sold to Mariner Energy effective 1 January 2008. In March 2008, we entered an agreement with Anadarko to acquire a 25% interest in the Kaskida discovery. (The transaction is subject to government approval and the acquisition of the Kaskida discovery is also subject to other parties not exercising preferential rights to purchase. As of 4 April, the company has been formally notified that two of such parties intend to exercise their preferential rights.)

Alaska
StatoilHydro was the high bidder on 16 leases, of which 14 were joint bids with ENI Petroleum, in Chukchi Sea Lease Sale 193 in Alaska, announced on 6 February 2008. StatoilHydro will be the operator of all leases. The Chukchi Sea is located offshore Alaska northwest of Prudhoe Bay, in water depths from 20 to 80 metres. The area is considered a frontier area with no production or infrastructure as of today. Our winning bids are subject to review and final approval by the MMS.

3.2.3.2 Latin America

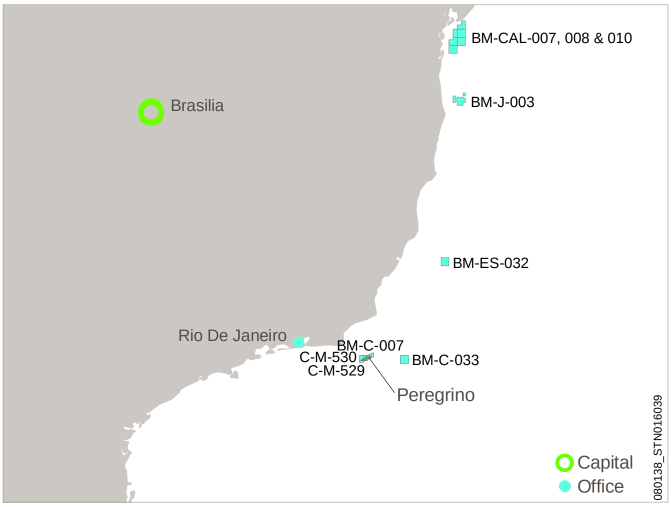
3.2.3.2.1 Venezuela

We completed the third and last well of the minimum exploration programme in **block 4, Plataforma Deltana**, Eastern Venezuela in October 2007. The campaign, which was initiated in December 2004, found gas-bearing sands in the Cocuina area. The Orca and Ballena wells did not encounter commercial gas volumes.

We are the operator of Plataforma Deltana Block 4 and have informed Venezuela's Ministry of Energy and Petroleum that we intend to retain the acreage around Cocuina in order to assess its commerciality and to return the rest of the acreage in the block.

3.2.3.2.2 Brazil

We have interests in seven exploration licences in four different basins in offshore waters in Brazil. We are operator for two of them. In addition, in 2008 we signed an agreement with Anadarko to acquire the remaining share and to become the operator with a 100% interest in the large Peregrino field in licence BM-C-7 in the Campos Basin. (The transaction is subject to government approval.) One appraisal well was drilled in block BM-C-7 in 2007 and resulted in a discovery.



License BM-J-3, operated by Petrobras, entered into the second exploration phase in 2005. The second exploration phase (three years), has a two-well work commitment and triggered relinquishment of 50% of the original area. We also have one commitment well in BM-CAL-10, one in BM-CAL-7 and two commitment wells in BM-C-33.

In the 8th Bid Round in 2006, together with Petrobras and Repsol, we had the highest bids for three blocks in the deepwater Santos Basin. In 2007, we participated in the 9th Brazilian Bid Round and, together with Anadarko Petroleum, we successfully bid for two blocks in the Campos Basin. They were awarded in March 2008, giving us a 50% interest in blocks C-M-529 and C-M-530. The blocks won in the 8th Bid Round have not yet been awarded by the government. Pending the award by the government, we successfully bid for a 30% interest in blocks S-M-1105 and 1109 and the operatorship and a 40% interest in block S-M-1233.

3.2.3.3 North Africa

3.2.3.3.1 Algeria

The **Hassi Mouina** licence was officially awarded in July 2004, and we have a 75% equity share in the licence. We are the operator in the exploration phase.

The Hassi Mouina block extends over 23,000 square kilometres and is situated in the western/central part of Sahara in an under-explored area. The three-year exploration period expired on 14 March 2008. A second exploration period with a one well commitment was approved by Sonatrach. A 30% relinquishment of our interest in the block is part of the contractual terms under the exploration PSA on transition from the first to the second exploration period.

During 2007, we completed the seismic work programme (started in 2005), one appraisal well and two exploration wells. All three wells resulted in gas discoveries. The work programme commitments for the initial exploration period were fulfilled by the end of 2007. A fourth well (exploration well TMS-1) has been completed and announced as a discovery in the first quarter of 2008.

3.2.3.3.2 Libya

In the exploration production sharing agreement (Epsa) IV bidding round in October 2005, three licences were awarded to StatoilHydro. The licences, all operated by StatoilHydro, were ratified in December 2005, initiating a five-year exploration period.

Area 94 (100% interest) covers an area of 9,849 square kilometres on the south-eastern Cyrenaica Platform with a commitment of one exploration well and 2D seismic.

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

Area 171 (50% interest) covers an area of 11,305 square kilometres in the Kufra basin with a work commitment of two exploration wells and 2D seismic.

The seismic commitments were fulfilled in 2007 for all three licences.

In addition, we have a 20% interest in **Areas 186/7** operated by Repsol. During 2007, 13 wells were drilled, two of which were discoveries. Drilling is expected to continue until the end of the current licence period in May 2008.

3.2.3.3.3 Egypt

StatoilHydro is operator with an 80% interest in two offshore exploration licences located in the Mediterranean, west of the Nile Delta at water depths ranging from sea level to 3,000 metres. Production Sharing Agreements for both blocks were signed in July 2007.

El Dabaa Offshore (Block 9) The block covers an area of 8,368 square kilometres. We are committed to drilling one exploration well and conducting 2D and 3D seismic surveys over a four-year period. Nine hundred kilometres of 2D seismic was acquired in 2007.

Ras El Hekma Offshore (Block 10) The block covers an area of 9,802 square kilometres. The related work commitment includes 2D and 3D seismic surveys over a four-year period. Seventeen hundred kilometres of 2D seismic was acquired in 2007.

3.2.3.4 Sub Saharan Africa

3.2.3.4.1 Angola

StatoilHydro holds interests in blocks 4/05, 15, 15/06, 17, 31 and 34 in Angola. Seven wells were completed in 2007, with four announced as discoveries.

Block 4/05 (20% interest) is operated by Sonangol. The commitment of one exploration well was fulfilled in 2007.

Block 15 (13.33% interest) is operated by ExxonMobil. A total of 34 exploration and appraisal wells have been drilled to date with 20 discoveries announced. All exploration commitments have been met and expired exploration acreage has been handed back to the authorities.

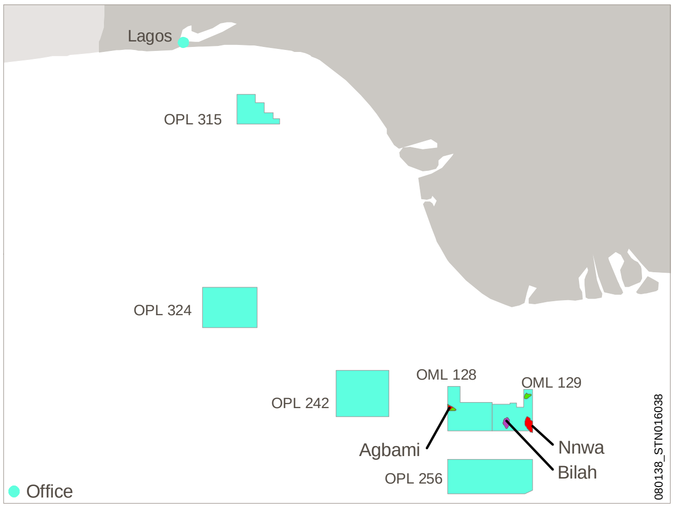
Block 15/06 (5% interest) Eni is the operator of the block we acquired in 2006. The work commitment for block 15/06 is extensive, covering 3D seismic surveys and including the drilling of eight wells, to be carried out during the first five years of the exploration phase.

Block 17 (23.33% interest) is operated by Total. To date, a total of 30 exploration and appraisal wells have been drilled with 16 discoveries announced, and, as a result, all exploration commitments have been met. Expired exploration acreage has been handed back to the authorities.

Block 31 (13.33% interest) is operated by BP. In 2007, four wells were completed with three discoveries, and to date a total of 21 exploration wells have been drilled in the block. The exploration period ends on 1 June 2008 and all commitments have been met.

Block 34 (50% interest) We are the technical assistant to the operator, the Angolan national oil company Sonangol P&P. In 2005, Sonangol P&P signed an agreement with the concessionaire to enter into the second exploration phase for Block 34. One exploration well remains to be drilled in block 34 and alternative exploration models will be evaluated for the well.

3.2.3.4.2 Nigeria



StatoilHydro is operator for two deepwater exploration licences, OML 128 and OML 129. In addition, we have shares in four exploration licences**:** OPL 324 and 315, operated by Petrobras, OPL 242 and OPL 256, which we acquired through the acquisition of Spinnaker and which are operated by Ocean Energy (Devon).

OML 128. (53.85% interest). In addition to the Agbami field, which is expected to come on stream in mid-2008, two leads have been identified in the block. A new 3D survey is planned for 2008.

OML 129. (53.85% interest). There are two discoveries in the block, Bilah and Nnwa.

Only one well has been drilled in the **Bilah** condensate discovery so far.

The **Nnwa** discovery extends into the Shell-operated Block OML 135 (known as the Doro structure). In 2007, StatoilHydro and Shell (SNEPCO) initiated a joint subsurface project with the aim of developing a common reserve base and appraisal strategy for the combined NnwaDoro structure. This project will continue in 2008.

OPL 315. In 2005, we were awarded a 45% share in block OPL 315 with Petrobras as operator. The licence is committed to carrying out a work programme by February 2011 consisting of one well and a seismic survey.

OPL 324 (25% interest) The second commitment well, Kiniun-1, was drilled in 2006. All commitments have been fulfilled and the block will be relinquished in 2008

OPL 242 (15% interest) One commitment well was drilled in 2007, Opukiri-1. All exploration obligations have been fulfilled.

OPL 256 (12.5% interest) The third commitment well in this block, Ofuruma-1, was drilled in 2007. Obligations have been fulfilled and an application for relinquishment of the entire block is pending approval.

3.2.3.4.3 Tanzania

StatoilHydro gained access to **Block 2** during a licence round in 2005. A PSA was signed in April 2007 with the Tanzanian Government and the Tanzanian Petroleum Development Cooperation (TPDC). We are the operator, with a 100% interest.

The total area of Block 2 is 11,099 square kilometres and it lies at water depths between 400 to 3000 metres. The deepwater acreage off the Tanzanian coast is divided into 12 blocks, all of which have been awarded during the last few years. This is a frontier area. No wells have been drilled this far from the coast so far.

The exploration period is divided into three stages:

- The First Exploration Period of four years with a seismic 2D commitment
- The First Extension Period of four years with a drilling commitment
- The Second Extension Period of three years with one well drilling commitment

We established a local office in Dar es Salaam in late 2007. The 2D seismic acquisition is planned for 2008.

3.2.3.5 Caspian

3.2.3.5.1 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.

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 1,400 square kilometres and is located at 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.

The first well of three commitment wells in the area is planned to be drilled within 12 to 18 months after settlement of the border issue, and a drilling location for this first well has been identified. Negotiations with SOCAR, the State Oil Company of Azerbaijan, have resulted in a freezing of the licence fee until the border issue is resolved, as well as in an extension of the exploration period until six months after the completion of the third well. It is not expected that the border issue will be resolved by 2008.

3.2.3.6 Western Europe

3.2.3.6.1 The United Kingdom

StatoilHydro is a 30% partner in a group of Chevron-operated exploration licences west of Shetland. In 2005, a discovery was made in the original license on the Rosebank/Lochnagar prospect. A three-well drilling programme to appraise this discovery commenced late in 2006.

Three appraisal wells and a sidetrack were completed in 2007, with one announced discovery. Chevron plans to return to exploration/appraisal drilling in the area in late 2008 or early 2009.

In 2007, we completed the acquisition of the discoveries Mariner (our interest is 44.44%), Mariner East (62.0%) and an additional 65.63% equity in Bressay (81.63%) on the UKCS from Chevron. StatoilHydro is the operator of these discoveries. In addition, a separate agreement was entered into with the Canadian companies Silverstone and Wilderness for the right to participate in the Broch discovery in block 9/16. Equity (30%) and operatorship of the Broch licence was transferred to us in March 2008. These are all heavy oil discoveries which are currently under appraisal.

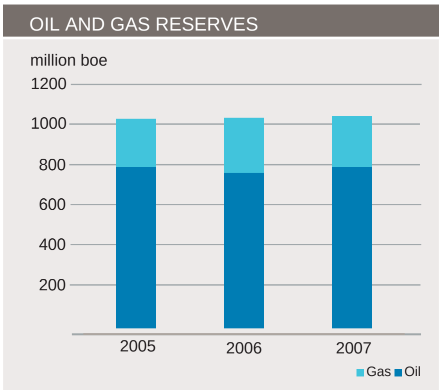
3.2.3.7 Other areas

3.2.3.7.1 Indonesia

We were awarded one offshore exploration share in the deepwater Kuma block in January 2007. The Kuma block lies directly off the west coast of Sulawesi and covers an area of over 5,000 square kilometres. Water depths are between 1,000 and 2,000 metres. Our share in the Kuma block is 40% and ConocoPhilips is the operator. The work commitment consists of 2D seismic and one exploration well.

In March 2007, StatoilHydro, together with PT Pertamina (Persero), was awarded the Karama offshore exploration block located adjacent to the Kuma block. We are the operator, with a 51% share. The three-year work commitment consists of 3D seismic and three exploration wells.

3.2.4 Oil and gas reserves



The proven reserves of the international business area increased by 0.7% in 2007, from 1,032 mmboe to 1,039 mmboe.

New projects sanctioned in 2007 were the most important driver behind the increase in reserves. The Peregrino project in offshore waters of Brazil was sanctioned in March 2007, and the Pazflor project on block 17 in Angola was sanctioned in December 2007. Revisions of existing estimates had a net positive impact on the 2007 accounts.

The expected future oil price used as the basis for entitlement calculations has risen substantially in 2007 compared with 2006. This has contributed negatively to our proved reserves of international fields which are regulated by PSAs.

Acquisitions and divestments during 2007 had no effect on the international proved reserve balance. North American Oil Sands Corporation was officially taken over by StatoilHydro in the middle of 2007, but the current maturity level of the asset does not justify recognition of proved reserves.

The share of developed reserves at year end 2007 was 456 mmboe, which is up 18.5% from 2006. Of the 2007 reserves, 785 mmboe are oil/NGL and 40.4 bcm (1,426 bcf) are natural gas.

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 32 - Supplementary oil and gas information - to our Consolidated Financial Statements.

Year		Oil/NGL mmbbls	Natural gas bcm	bcf	Total mmboe
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
2005	Proved reserves end of year	779	39.4	1,392	1,025
	of which proved developed reserves	295	6.0	208	332

3.2.5 Production

StatoilHydro's petroleum production outside Norway amounted to an average of 307 mboe per day entitlement production and 422 mboe per day equity production in 2007. The total annual entitlement production in 2007 was approximately 112 mmboe compared with 85 mmboe in 2006.

Field	StatoilHydro's equity interest	Operator	On stream	License expiry	Producing wells	Development wells	Average daily entitlement production [1] mboe/day
Canada: Hibernia	5.00%	HMDC	1997	2027	30	2	**6.7**
Canada: Terra Nova	15.00%	PetroCan	2002	2022	15		**17.4**
USA: Lorien	30.00%	Noble	2006	2012	2	1	**3.0**
USA: Front Runner	25.00%	Murphy Oil	2004	2010	3	1	**2.6**
USA: Spiderman Gas	18.33%	Anadarko	2007	2012	3	2	**0.9**
USA: Q Gas	50.00%	StatoilHydro	2007	2014	1		**1.3**
USA: San Jacinto Gas	26.67%	ENI	2007	2012	2	1	**1.1**
USA: Zia	35.00%	Devon	2003	2007 (2)	1	1	**0.6**
USA: Seventeen Hands	25.00%	Dominion	2006	2010	1		**0.9**
USA: Shelf	100.00%	Various	Unified	Various	42	8	**12.8**
Total North America					100	16	**47.4**
Venezuela: Sincor	15.00%	Sincor	2001	2037	384	86	**20.9**
Total Latin America					384	86	**20.9**
Algeria: In Salah	31.85%	Sonatrach/BP/StatoilHydro	2004	2027	25	1	**25.9**
Algeria: In Amenas(3)	50.00%	Sonatrach/BP/StatoilHydro	2006	2022	12	1	**9.7**
Libya: Mabruk	25.00%	Total	1995	2028	57	1	**2.2**
Libya: Murzuq	8.00%	Repsol	2003	2023	67	1	**3.6**
Total North Africa					161	4	**41.4**
Angola: Kizomba A	13.33%	ExxonMobil	2004	2026	25		**18.0**
Angola: Kizomba B	13.33%	ExxonMobil	2005	2027	19		**17.1**
Angola: Xikomba	13.33%	ExxonMobil	2003	2027	1		**1.3**
Angola: Marimba North	13.33%	ExxonMobil	2007	2027	2		**1.1**
Angola: Girassol/Jasmim	23.33%	Total	2001	2022	24		**19.0**
Angola: Dalia	23.33%	Total	2006	2026	16	1	**43.4**
Angola: Rosa	23.33%	Total	2007	2027	7	2	**9.4**
Total Sub Saharan Africa					94	3	**109.2**
Azerbaijan: ACG	8.56%	BP	1997	2024	43	6	**50.2**
Azerbaijan: Shah Deniz	25.50%	BP	2006	2031	4	1	**17.8**
Total Caspian					47	7	**68.0**
UK: Alba	17.00%	Chevron	1994	2018	36		**7.2**
UK: Caledonia	21.32%	Chevron	2003	2018	1		**0.1**
UK: Dunlin	28.76%	Shell	1978	2017	13		**0.9**
UK: Jupiter	30.00%	ConocoPhillips	1995	2010	14		**1.1**
UK: Merlin	2.35%	Shell	1997	2017	3		**0.0**
UK: Schiehallion	5.88%	BP	1998	2017	21		**2.9**
Total Western Europe					88		**12.3**
China: Lufeng	75.00%	StatoilHydro	1997	2011	5		**2.8**
Russia: Kharyaga	40.00%	Total	1999	2032	11		**5.1**
Total Other areas					16		**8.0**
Total International E&P					890	116	**307.2**

[1] Production figures are after deductions for royalties, production sharing and profit sharing.

[2] Held by production.

[3] Production under the terms of the PSA commenced December 2006.

The following table shows our average daily entitlement production of oil, including NGL and condensates, and natural gas for each of the years ending 31 December 2007 and 2006. The new fields that came on stream in 2007 were Spiderman, Q and San Jacinto in the US Gulf of Mexico and Rosa and Marimba North in Angola.

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

3.2.6 Fields under development and in production

This section covers projects under development and fields in production. Pre sanctioned projects including some discoveries in early phase evaluation are also presented. Exploration activities are described in the previous section Exploration Activity. This section often refers to a field's plateau production. This refers to yearly average equity production at plateau for a field, 100% (not our share). Capacities also refer to the total field or facility, 100% share. The number of development wells as of 31 December 2007 for producing fields is provided under Production above. The total number of development wells in fields under development, that were already drilled or undergoing drilling as of year end 2007 was 75.

3.2.6.1 North America

StatoilHydro's E&P activities in North America comprise interests in the US Gulf of Mexico, off the eastern coast of Canada, and oil sands activities in the Alberta province in onshore Canada.

3.2.6.1.1 Canada

Oil Sands

In June 2007, we acquired 100% of the shares in NAOSC for approximately USD 2.0 billion. 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 order to determine the extent of the exploitable bitumen pools, a total of 286 exploration and delineation wells were drilled by NAOSC in the region from 2003 to 2007. In its raw state, bitumen is a heavy viscous, tar-like form of oil that we plan to produce using the steam assisted gravity drainage method (SAGD) from a depth of approximately 1,400 feet with an average producing zone thickness ranging from 50 to 100 feet. The project life is expected to exceed 20 years and it will be developed in phases.

The Leismer SAGD Demonstration Project was sanctioned by the board of directors in December 2007 with a capacity of 20,000 boe per day, and we anticipate the sanctioning of further project phases after 2009. Initial production is scheduled for mid-2010. Also, in August 2007, we submitted an application to the Alberta regulatory authorities for the full 220,000 boe per day commercial SAGD project.

In December 2007, we submitted an application to the Alberta regulatory authorities for the construction of an upgrader to process the bitumen into lighter synthetic crude oil.

East Coast Offshore

East coast offshore consists of non-operated, mature oil production from the Hibernia and Terra Nova fields and two discoveries under appraisal - Hebron and Hibernia Southern Extension. Operational challenges include harsh weather conditions and ice management.

Discoveries under appraisal

The **Hebron** oilfield was discovered in 1981. The field is operated by Chevron and our interest is 10.2%. The Hebron partners signed a Unitisation and Joint Operating Agreement in 2005. Negotiations with the Provincial Government resumed in 2007 and resulted in the signing of a Memorandum of Understanding. Development will probably comprise a gravity-based structure platform (GBS) supporting all modules (production, development and quarters) and developing several reservoirs.

The Hibernia Southern Extension project operated by ExxonMobil comprises the development of resources in several fault blocks to the far south of the existing Hibernia Main Field. The submission of a Development Plan Application is planned for 2008 pending commercial agreement within the partnership and the signing of a Memorandum of Understanding with the Provincial Government.

Fields in production

The **Hibernia** field is developed with an iceberg-resistant GBS type platform which supports all topside facilities, twin-drilling derricks and living quarters. Crude is stored in caissons in the GBS and offloaded to tankers. The field is producing from 51 wells, including several world-class extended reach drilling wells.

Terra Nova. Subsea wells are centred in four iceberg scour resistant excavations on the seabed. Wells are connected to a double-hulled, ice-reinforced FPSO via production and injection risers. Terra Nova's production efficiency is low due to a number of technical issues on the FPSO. Several initiatives are underway to improve reliability of the production system.

3.2.6.1.2 U.S. Gulf of Mexico

We have step by step built a high quality asset portfolio in US Gulf of Mexico through a clear strategy combining acquisitions and exploration.

Discoveries under appraisal

The **Jack** oil field is located at Walker Ridge 758/759, approximately 250 miles south-west of New Orleans, Louisiana. Jack, which was discovered in 2004, was part of the acquisition of Encana's US GoM deepwater properties in 2005. Chevron is the operator, and we have a 25% interest. We are planning further appraisal activities in 2008. An integrated project team has been formed and it is evaluating various development concepts.

St. Malo, located at Walker Ridge 678, is operated by Chevron and it was also part of the Encana acquisition in 2005. St. Malo and Jack are in approximately 7,000 feet of water and separated by approximately 25 miles. We have a 6.25% interest in St. Malo. Currently, an integrated project team is exploring various development solutions at St. Malo, and we are planning further appraisal activities in 2008.

Fields under development

The **Tahiti** field located at Green Canyon 640 was the core field acquired in our 2005 acquisition of Encana's deepwater Gulf of Mexico properties. We have a 25% interest in the Chevron-operated field. The Tahiti development will consist of a Spar production platform connected to two subsea drill centres with production capacity of 125,000 bbl per day. Originally, first production was planned for mid-2008. However, in June 2007 we were notified of a problem with the mooring shackles, which is expected to delay the hull installation by 10 to 12 months. First production on Tahiti is now estimated to occur in the second half of 2009.

We acquired our 25% interest in the Murphy-operated oil field **Thunder Hawk** as part of the Spinnaker acquisition in 2005. The field is located at Mississippi Canyon 734. The field will be developed with a floating semi-submersible 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

As of 31 December 2007, we produced oil and gas from several deepwater fields as well as many shelf fields in the GoM.

Our **Eastern Gulf** fields were part of the Spinnaker acquisition in 2005. Our deepwater natural gas fields comprising Spiderman, San Jacinto and Q made us as a key player in the development of the Eastern GoM. The fields in the Eastern Gulf were developed via subsea tie-back to the Independence Hub, a floating production facility installed in 2007 on Mississippi Canyon Block 920. The Independence Hub was constructed and is owned by third parties and is capable of processing one billion cubic feet of natural gas per day. We own 12.7% of the capacity of the hub. Spiderman, San Jacinto and Q commenced production as the Independence hub came on stream in fourth quarter 2007.

Lorien, located at Green Canyon 199, is producing through a two well subsea tie-back to Shell's Bullwinkle platform. In June 2007, Lorien experienced an unexpected one-month shut-in. Subsequent to the shut-in, production has not been restored to its previous rates. The operator, Noble Energy, is currently evaluating scenarios to fully deplete the reservoir.

We acquired our 25% interest in the Murphy-operated **Front Runner** field as part of the Spinnaker acquisition in 2005. Due to production shortfalls, we announced an extensive review of the field in October 2006 to determine whether the recoverable resources estimated at the time of the acquisition could be produced from the field's reservoirs. Our review concluded that the geology of Front Runner is more complex and the reservoir communication weaker than expected at the time of acquisition. As a result, the expected recoverable reserves from Front Runner were reduced by 56% due to lower expected volumes of oil in place and reduced expected recovery rates.

The Spinnaker acquisition also gave us interests in **Zia and Seventeen Hands**, which are two smaller deepwater fields located at Mississippi Canyon 496 and 299, respectively.

Shelf.

At year end 2007 we produced oil and gas from 32 blocks on the shelf. All our former Spinnaker assets on the shelf were sold to Mariner Energy effective 1 January 2008.

3.2.6.2 Latin America

Our current asset portfolio in Latin America comprises our interest in the onshore extra heavy oil producing asset named the Petrocedeño Mixed Company (the former Sincor project), and the heavy oil Peregrino development project in Brazil. We are also pursuing positions in Mexico and have a representation office in Mexico City.

3.2.6.2.1 Venezuela

The Petrocedeño project (former Sincor project) involves the exploitation of extra heavy crude oil from the reservoirs in the Orinoco Belt. A diluent is added in order for the 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. Sincor C.A., owned by the project partners, operates the field and is responsible for the development, operation, upgrading and marketing of its products.

At year-end 2007, we held a 15% share in the Sincor project. A major maintenance turnaround is scheduled for 2008 to perform activities to grant operational reliability of the Upgrader according to the maintenance plan. During this period light oil upgrading will be affected and it is expected that heavy oil will be produced and marketed as diluted crude oil.

In 2007, Decree-Law 5.200 for Migration mandates the transformation of Sincor and other oil projects into incorporated joint ventures with minimum majority participation by the state of 60%. As a result, our participation in Sincor will be reduced to 9.677% after the migration to an incorporated entity is completed as mandated by law. The new mixed company, known as Petrocedeño, S.A., was incorporated in late 2007. Petrocedeño, S.A. became effective from 9 February 2008.

The transfer of control of operations of the Sincor project on 1 May 2007 and the signing of the Memorandum of Understanding on 26 June 2007 relating to the migration into a mixed company necessitate changes to the Sincor financing agreements. Petrocedeño, S.A., is financed with a mix of shareholders equity and debt.

The lenders to the former Sincor project have come to agreement on all terms and conditions related to the financing of Petrocedeño, S.A. The financing agreements have been signed and took effect as of the date of closing.

3.2.6.2.2 Brazil

In March 2008 StatoilHydro and Anadarko signed an agreement whereby StatoilHydro will take over the remaining 50% in the Brazilian **Peregrino** project, offshore off Brazil. This will give StatoilHydro a 100% working interest and operatorship of the development. The transaction is pending governmental approval. The development was sanctioned by the partners in March 2007 and approved by the Petroleum National Agency in May 2007.

The field will be developed with an FPSO and two drilling/wellhead platforms. The first oil is planned to come on stream within 2010 and peak production of 100 mboe per day is expected to be reached within the first year of production.

3.2.6.3 North Africa

StatoilHydro has interests in onshore producing assets in the North African countries Algeria and Libya.

3.2.6.3.1 Algeria

We have a position as a significant gas seller in Europe. Our strategy is to serve this market from multiple sources. Due to its close vicinity to Europe, Algeria is an attractive country that can contribute to realise this strategy.

The decision to enter into Algeria was made in 2003 and our engagements in all assets have a long-term perspective. The overall security and political situation is monitored continuously. We recognise the need for a greater level of protection for personnel and property compared with Europe. Appropriate measures are continuously being assessed based on the perceived risk level. In our evaluation the current risk level will continue throughout 2008.

Algeria. In Salah

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.

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.

The rights and obligations are governed by a production sharing contract, giving BP and StatoilHydro access to a share of the liquid volumes only. The production of gas started up in mid-2006 and the production of the liquids commenced in December 2006**.** Following initial start-up challenges the production is now at stable levels.

3.2.6.3.2 Libya

Fields in production

The **Mabruk** West onshore oil field is situated in the north of Libya. The Libyan authorities approved a field development plan (FDP), for Mabruk Phase IV in Mabruk Central and East in July 2004. The development includes the construction of new facilities and the drilling of additional development wells in East and West Mabruk. The new gas oil separation plant came on stream in June 2007.

The FDP for Mabruk Phase V covering the Dahra and Gharian areas has not yet been formally approved by the Libyan authorities.

Murzuk consists of several fields within the Murzuk basin. Production from the NC 186 A-field started in 2003, the NC 186 D-field commenced in 2004, and the NC 186 B and H fields came on stream in 2006. The 186 A, B, D and H fields are being developed with one common processing facility. Oil from these fields is transported from the NC 186 gas oil separation plant and blended with oil from NC 115 and then transported by pipeline to the Az Zawia terminal west of Tripoli. The FDP for the NC 186/115 I/R field was approved by Libya's National Oil Company (NOC) in September 2007.

The master development plan for the Murzuq gas utilisation project Phases I and II was finalised in June 2007, and the project is expected to be completed in late 2009.

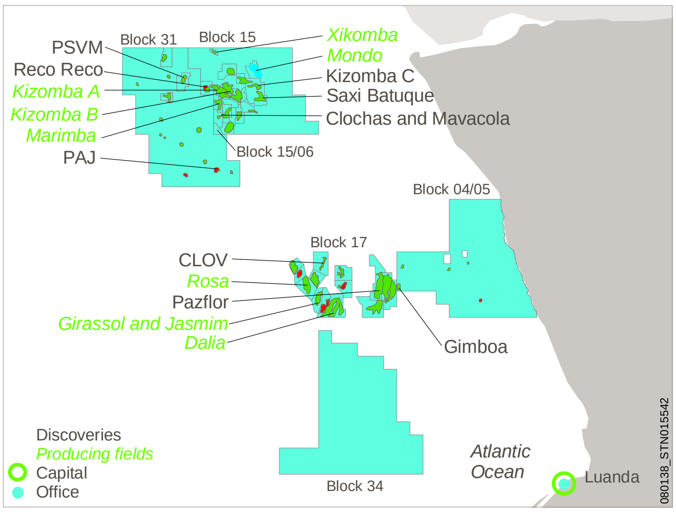
NOC has initiated renegotiation of the existing production and sharing agreements with independent oil companies operating in Libya in order to increase the Libyan share of production. NOC's aim is to have all production and sharing agreements in Libya updated to the latest standard, the Exploration Production Sharing Agreement - concession round IV format. NOC is currently reviewing the contracts for licence 186 in Murzuq and C-17 in Mabruk, where StatoilHydro is a partner.

3.2.6.4 Sub Saharan Africa

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

3.2.6.4.1 Angola

The Angolan continental shelf is the largest contributor to StatoilHydro's present production outside Norway. It yielded more than 100 mboe per day in entitlement production at the end of 2007, representing approximately 35% of the group's total international oil and gas output. FPSO vessels with subsea wellheads are the preferred oil-field development concept in deepwater Angola due to the great water depths, high production volumes and lack of infrastructure.



Current production from Angola comes from the Kizomba A, Kizomba B, Xikomba, Marimba North and Mondo fields in block 15, and Girassol, Jasmim, Rosa and Dalia fields in block 17. Marimba North and Rosa came on stream in 2007 and Mondo came on stream 1 January 2008. Gimboa in block 4 and Saxi Batuque in block 15 are both expected to commence production in 2008.

In December 2007 the operator Total announced that the Pazflor field in block 17, is ready for development. A new development project, PSVM in block 31, is expected to be approved in 2008. Work is also ongoing to pursue the CLOV development in block 17, additional development hubs in block 31 and satellites like Clochas and Mavacola in block 15.

Block 17 is operated by Total and our interest is 23.33%. Production from the block currently comprises the Girassol, Jasmin, 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, commenced production in December 2006, and is expected to reach peak production level of 240 mboe per day in 2009. The first oil from Rosa**,** a tie-back to the Girassol FPSO, was produced in June 2007 and the peak production level of 150 mboe per day is expected to be reached in 2008. The combined production on the Girassol FPSO has a capacity limit of 250 mboe per day.

The Pazflor project comprises the discoveries Perpetua, Acacia, Zinia and Hortensia. Pazflor was sanctioned in 2007 by StatoilHydro and Sonagol approved the main contracts by the end of 2007. The FPSO is expected to have a peak production of 200 mboe per day, with start-up scheduled in 2011. After the planned commencement of production in the Pazflor development project, the installed production capacity on block 17 will be approximately 700 mboe per day.

Work is ongoing to pursue the common development of four additional discoveries, Cravo, Lirio, Orchidea and Violeta which will comprise another potential development called CLOV.

Angola. Kizomba A

We have a 13.33% interest in **block 15**, which is operated by ExxonMobil. Three FPSOs were in production at 31 December 2007: Kizomba A, Kizomba B and Xikomba. On 1 January 2008, the Kizomba C-Mondo FPSO started production. One more FPSO, Kizomba C-Saxi/Batuque, is expected to come on stream in 2008.

Kizomba A, which encompasses the Hungo and Chocalho discoveries, commenced production in August 2004, and peak production of 250 mboe per day was reached in 2006. Marimba North commenced production as a tie-back to the Kizomba A FPSO in September 2007**.** 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 A is expected to fall off plateau in the second quarter of 2008. Kizomba B, which encompasses the Kissanje and Dikanza discoveries, commenced production in July 2005. Xikomba is a small, isolated discovery producing from a leased FPSO. The Kizomba C-Mondo and Kizomba C-Saxi/Batuque projects were sanctioned in 2005. The Kizomba C-Mondo FPSO started up on 1 January 2008. The Kizomba C-Saxi/Batuque FPSO is expected to start up in mid-2008. The combined Kizomba C production is expected to reach plateau levels of 200 mboe per day in 2009.

Work is also ongoing to pursue the development of two medium-sized discoveries: Clochas and Mavacola.

This ultra deepwater licence on b**lock 31** is operated by BP, and we have a 13.33% interest. The common development of the first four discoveries in the northern part of the block, Plutao, Saturno, Venus and Marte (PSVM) is expected to be approved in 2008. Two to four additional production hubs are expected to be launched.

The Gimboa field, which is located in **block 4/05**, was sanctioned in April 2006. The operator for the block is Sonangol P&P and we have a 20% interest in the block. Peak production from the field is expected to be 35 mboe per day and the FPSO is expected to start production in the second half of 2008.

In 2007, an investment decision on a **gas export project** was sanctioned for block 15. For block 17, Phase 1 of the project, comprising gas storage in block 2, was sanctioned in 2007. Angola LNG will use the gas. We are not a partner in Angola LNG, but all costs will be recovered under the terms of the PSAs and providing a gas export solution makes it possible to avoid loss of oil recovery on the fields. Planning is ongoing for Phase 2 of the project for block 17, comprising the transportation system to Angola LNG .

3.2.6.4.2 Nigeria

Even with a newly elected government in place, the political situation remains unstable, particularly in the strategically important oil region in the Niger Delta. Consequently, 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.

The **Agbami** field in deep waters off Nigeria is developed with an FPSO and first oil is expected in 2008. Agbami, operated by Chevron, is located in licences OML 127 and OML 128, and our interest in the unitised field is 18.85%. The Agbami field is expected to reach a plateau production of 230 mboe per day from mid-2009.

The Nigerian Department of Petroleum Resources has initiated a process to review the terms of the 1993 production sharing contract terms. The affected deepwater operators in Nigeria (seven companies) have been asked to form a joint operator group for this purpose.

3.2.6.5 Caspian

StatoilHydro's current interests in the Caspian area comprise projects in Azerbaijan and a representative office in Kazakhstan.

3.2.6.5.1 Azerbaijan

In 1992, we established a presence as one of the first international oil companies in the Caspian Sea. 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. 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 further described in this report section and the Alov, Araz and Sharg prospects described under report section Operational review-International E&P-Exploration activity.

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 existing risks should not be underestimated.

Ongoing negotiations concerning the Caspian Sea. A binding legal regime governing the division of the Caspian Sea between the five border states of Azerbaijan, Iran, Kazakhstan, Turkmenistan and Russia is yet to be agreed. This has on occasion led to disputes over rights to hydrocarbon resources between Azerbaijan and Iran and between Turkmenistan and Azerbaijan. There are currently bilateral agreements in place between Russia, Kazakhstan and Azerbaijan.

StatoilHydro is a partner with an 8.56% interest in the BP-operated **ACG** PSA. The ACG field development is being developed in three phases in addition to the Early Oil Production phase (EOP). We expect overall daily production from ACG to reach the plateau level of around one million bbl per day by 2010.

The Chirag platform has been producing as a part of **EOP** since November 1997 and it is currently producing at stable levels.

ACG Phase I has been completed with the exception of water injection, which commenced during 2007 and will be completed in 2008. Central Azeri started oil production in early 2005 and gas injection started in 2006.

All construction activities have been completed on **ACG Phase II**. West Azeri commenced oil production in 2005 and East Azeri commenced oil production in late 2006.

The pre-drilling programme for **ACG Phase III** (Deep Water Gunashli development) commenced during 2005 and continued successfully in 2006. Overall Phase III construction activities are progressing on schedule. Two offshore platform jackets with topsides were installed during 2007. It is anticipated that the first oil from Phase III will be delivered during the second quarter of 2008. Total ACG production is expected to reach 900 mbbl of oil per day by the end of 2008. The Deep Water Gunashli subsea water injection facilities were sanctioned during 2006 and are planned to be operational in 2009.

Export of hydrocarbons. The Caspian Sea is landlocked, without direct access to open sea. The export of oil is therefore dependent on onshore pipelines. Currently, crude oil from ACG is transported to the Mediterranean Sea through the 1,760 kilometre Baku-Tbilisi-Ceyhan (BTC) Pipeline, in which we participate with an 8.71% interest. The commissioning of the BTC Pipeline ensured export flexibility through multiple pipelines and thereby spread the risk involved in commercialising the land-locked upstream resources. The BTC Pipeline was sanctioned in 2002 and completed in May 2006. In the fourth quarter of 2007, 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. The partners have completed a four-year exploration phase involving a three-dimensional seismic survey and the drilling of three wells. The partnership submitted a notification of a commercial discovery in 2001 and entered into a 30-year development and production period. StatoilHydro is the commercial operator covering gas sales, contract administration and business development for the Shah Deniz stage I. This appointment also covers the South Caucasus Pipeline system (SCP) for gas transport to markets in Azerbaijan, Georgia and Turkey. BP is field operator and we have a 25.5% interest.

Shah Deniz Stage I development on the eastern flank of the reservoir and a 680 kilometre long, 42-inch pipeline, from the landing terminal through Azerbaijan and Georgia to the Turkish border (SCP), was sanctioned by the partnership in 2003. The SCP system has been prepared for expanded capacity to facilitate future development stages.

Shah Deniz Stage I commenced production on December 2006, but the field had to be shut down due to well problems, in 2007all four pre-drilled wells were tied back and production resumed in February 2007. The plateau production from stage I is expected to be approximately 8.6 bcm (300 bcf) per year and to be reached after two to three years of production.

3.2.6.6 Western Europe

We have interests in producing and development assets in the UKCS and Ireland and an early phase evaluation asset in Denmark. 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 through to development the existing discoveries.

In 2007 we acquired several heavy oil discoveries on the UKCS, Bressay, Mariner/Mariner East and Broch. These are presented under section Exploration Activity.

3.2.6.6.1 United Kingdom

In 1983, the UK office was established as a trading office. Exploration and production activities, which started in 1987, were strengthened by the acquisition of Aran Energy PLC in 1995. We continue to participate as both partner and operator in UK licences

Fields in production
The UK portfolio comprises the fields Schiehallion, Alba, Caledonia, Dunlin, Merlin and Jupiter. Most of our UK fields are currently in tail-end production. In March 2008 we signed an agreement to divest our interest in the Dunlin and Merlin fields, effective 1 January 2008.

3.2.6.6.2 Ireland

The **Corrib** gas field, in which we have a 36.5% interest, lies on the Atlantic Margin north-west of Ireland. The Corrib field development, operated by Shell, was sanctioned in 2001 and the production licence was granted in late 2001 with a duration of 30 years.

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 October 2004. Project execution was suspended in July 2005 due to protests by some local landowners. Following a comprehensive safety review by the Irish authorities, work on the project recommenced in May 2006. Currently, six of the seven offshore wells have been drilled and civil work continues on the onshore terminal site. Construction of the gas terminal commenced in July 2007 and is ongoing. As part of a community consultation process, alternative pipeline routes have been identified, and the final planning application for the pipeline will be made by mid-2008.

3.2.6.6.3 Denmark

Discoveries under appraisal
We have a 25% interest in the **Hejre** field, operated by Dong, in licence 5/98. This is an undeveloped oilfield located at a water depth of 70 metres in the Danish sector of the North Sea. Field challenges include high pressure and high temperature reservoir. The partnership is in the concept evaluation phase.

3.2.6.7 Middle East

StatoilHydro is pursuing business development opportunities in the Middle East region and has representative offices in Riyadh (Saudi Arabia), Abu Dhabi and Dubai (United Arab Emirates), Doha (Qatar) and Amman (Jordan, covering Iraq).

3.2.6.7.1 Iran

In December 2002, we became operator for the development of the offshore part of the **South Pars phases 6/7/8** project under a buy-back contract with a 37% share during the development phase. The South Pars phases 6/7/8 offshore project comprises 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 the required reservoir management.

All three jackets were installed during the first part of 2004 at a water depth of 65 meters in the Persian Gulf. Drilling and completion of the 30 production wells was finalised in January 2006. Two of the 32 inch pipelines to shore have been installed, tested and are ready for commissioning. The SPM buoy has been completed.

Together with the SPD (South Pars Development) 7 tripods and flare tower, the SPD 9 platform topside was installed offshore during the spring of 2007. We are presently completing the SPD 9 platform for production start up in 2008 and are preparing SPD 7 and SPD 8 for onshore mechanical completion followed by offshore installation and production start up during 2008 and 2009. Planning for installation of the third pipeline is progressing.

StatoilHydro entered into a contract with the National Iranian Oil Company (NIOC) for exploration of the **Anaran** block close to the Iraqi border in April 2000. In 2003, our interest was reduced to 75% through a farm out to Lukoil. A discovery on the Azar structure was made in 2005 and a discovery on the Changuleh structure was made in September 2006. A commerciality report for Azar was submitted to NIOC in December 2005, and Azar was declared commercial by NIOC in the middle of 2006. A Master Development Plan for the combined development of Azar and Changuleh was submitted to NIOC in December 2007. Further review of the project is currently ongoing.

StatoilHydro signed an exploration and development service contract with NIOC for the **Khorram-Abad** block in Lurestan province in south-western Iran in September 2006. The block covers 7,400 square kilometres, and the work programme includes acquisition of 600 kilometres of 2D seismic and the drilling of three exploration wells. The seismic shooting started in August 2007 and is still ongoing.

See report section Risk review - Risk factors for additional information concerning the risk of US sanctions related to activities in Iran. See report section Risk review - Legal proceedings for additional information concerning the Horton Case.

3.2.6.7.2 Iraq

In 2005, the Norwegian Ministry of Petroleum and Energy signed a Memorandum of Understanding (MOU) with its Iraqi counterpart. We are participating in an institutional and technical assistance programme under this MOU. In addition, we have entered into our own Memorandum of Cooperation (MOC) with the Iraqi Ministry of Oil. Under this agreement, we have carried out joint exploration and field development studies, as well as provided technological assistance and transfer. This MOC was renewed in December 2007.

3.2.6.8 Other areas

3.2.6.8.1 China

We opened our first office in China in 1982. Today, our business involves operating the **Lufeng** field, oil trading, LPG trading and business development. Our partner on the Lufeng field is the China National Offshore Oil Company. The field, which already is well beyond original expected life, is still producing, and the current lease of the FPSO has now been extended through 2008.

In February 2007, we entered into a strategic partnership with China National Petroleum Corporation through the signing of a Memorandum of Understanding relating to domestic and international exploration and production cooperation, LNG projects and research and development.

3.2.6.8.2 Russia

We have been present in **Russia** since the early 1990s with a representative office in Moscow. We have one producing field, the Kharyaga oil field**.**

In October 2007, StatoilHydro signed a framework agreement with Gazprom to become a partner with 24% ownership in the Shtokman development company responsible for planning, financing and constructing the infrastructure necessary for the first phase of the Shtokman development, which will own the infrastructure for 25 years from start of commercial production. The implementation of the project is subject to a final investment decision which is planned to take place in the second half of 2009.

Field in production
The **Kharyaga** field is located onshore in the Timan Pechora basin in North West Russia. The Kharyaga PSA was signed between Total and the Russian Authorities in 1995 and became effective in 1999. 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 October 1999.

Phase 1 with production of 10,000 boe per day utilising three existing wells. **Phase 2** was launched in 2000 to increase oil production and develop additional reserves. An additional 10 wells were drilled during this phase. The **Phase 3** has now been initiated with the objective to increase production from 20 to 30 mbbl per day. This phase involves the drilling of more production and injection wells, process upgrade and the installation of gas treatment facilities for the sale of associated gas.

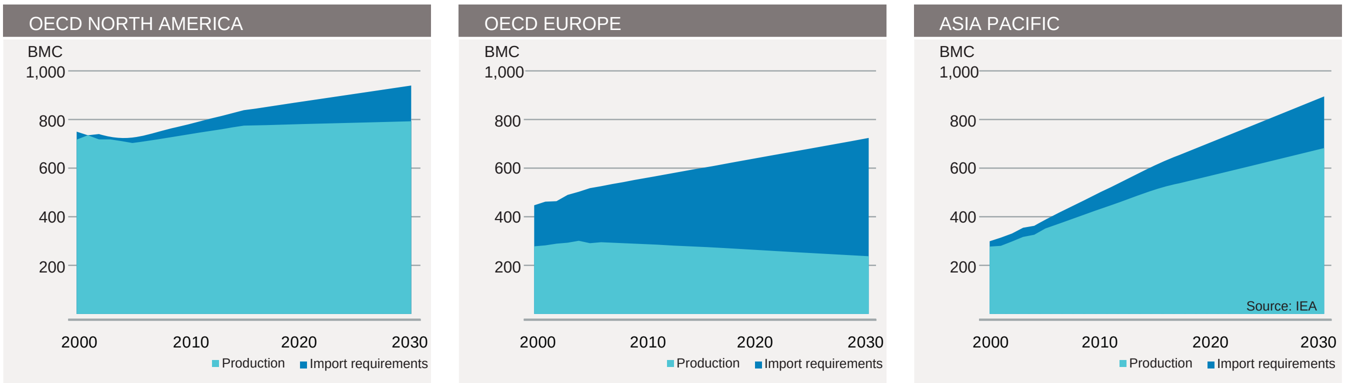
3.3 Natural Gas

3.3.1 Industry overview

According to the International Energy Agency's (IEA) World Energy Outlook for 2007, 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 the developing countries, coal is expected to see the fastest growth in demand, whereas natural gas is expected to continue to be the fastest growing fuel in OECD markets and transition economies.

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. Hence, the 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 the main gas-producing countries. In consequence, international natural gas markets will be influenced by policy decisions in key producing countries such as Russia, 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. High regularity and the geographical location makes NCS gas attractive in the European market. We therefore expect that demand for gas from Norway will continue to increase in our primary gas markets.

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

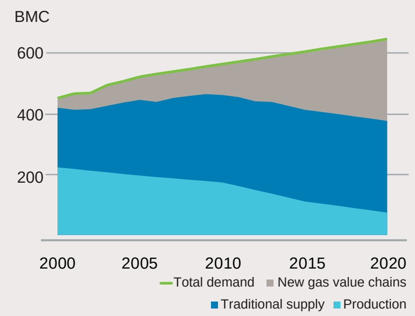
- Accelerated growth in energy demand driven by population and economic growth, with natural gas playing a more important role in the energy mix.
- Due to increased import dependency, natural gas will be transported over increasingly long distances, both as LNG and via pipelines.
- Environmental concerns and climate change policies are becoming increasingly 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, the estimated annual growth in global gas consumption in the period 2005-2030 will be 2.1%. Growth in OECD Europe in the same period is expected to be 1.4%. This translates into a European demand for gas in 2030 of approximately 770 bcm - approximately six times Norway's current export capacity. The share of gas in total primary energy consumption is approaching 25% in the OECD countries in Europe. Approximately 59% of the growth in gas consumption in the period is expected to come from the electricity sector. The IEA expects growth in demand for all sub-sectors of the European natural gas market.

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. In addition, we market gas sourced from producing areas other than the NCS. Other major gas suppliers in Europe are Gazprom from Russia, Sonatrach from Algeria and Gasunie from the Netherlands. We believe that Norwegian natural gas exports will remain highly competitive because of reliability, access to the transportation infrastructure and proximity to the European market. In addition, natural gas is an attractive source of energy from the perspective of climate change since it emits far less greenhouse gasses 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 engage further in Europe's largest and most liberalised natural gas market. A new export pipeline, Langeled, from the NCS to Easington in the UK is now in operation. Another new infrastructure project is the Tampen Link, a pipeline from the Statfjord field on the NCS to the existing Flags pipeline on the UK continental shelf, which was completed in 2007.

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 up 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.

At the same time, we are facing a more competitive downstream natural gas market in Continental Europe. However, we believe that our long-term relations with large customers, experience in the marketing of natural gas and established points of entry will put us in a strong competitive position. For more information about the EU Gas Directive, please see report section Regulation - Gas directive of the European Union.

3.3.3 Gas sales and marketing

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 November 2007, the Norwegian state announced that it would not support plans to increase gas production from the Troll field, due to the possible negative impact on future liquids production. In consequence, plans for an additional gas export pipeline from Norway were cancelled. We had previously expected that gas production from the Troll field could be used to provide significant gas volumes to the European market in the future. We are now working on a number of projects to realise the full potential of the NCS that will contribute to strengthening our position as an important and reliable long-term supplier of natural gas in Europe.

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) 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 by the fourth quarter of 2008 with full commercial operation of the nine cavern facility achieved in 2011. The design capacity for the storage facility is expected to be 420 mcm. StatoilHydro's share of the total development cost is estimated to NOK 0.7 billion.

In Germany, we hold a total 31.4% stake in the Norddeutsche Erdgas-Transversale, or Netra, overland gas transmission pipeline, and a 23.7% stake in Etzel Gas Storage through our subsidiaries Statoil Deutschland and Hydro Energie Deutschland.

StatoilHydro has a 25.5% share in the Shah Deniz field in Azerbaijan and is commercial operator with responsibility for gas transportation and all gas sales activities. Turkey is the main market for gas from Stage 1 of the Shah Deniz development, and in addition Georgia and Azerbaijan are part of the gas sales portfolio. The 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 2007.

Shah Deniz transportation solutions. Possible transportation solutions for the Shah Deniz stage 2 gas to the European market.

The Stage 2 development of Shah Deniz is currently being progressed toward a planned start-up in the end of 2013. Field reserves support a significant Stage 2 development and is likely to be on a similar or larger scale as Stage 1 (with plateau production of approximately 8.6 bcm). 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 and the European Union. In February 2008, StatoilHydro signed an agreement with EGL to establish a joint venture to develop, build and operate the Trans Adriatic Pipeline (TAP) from Greece, through Albania to Italy. A final investment decision is to be made in the second half of 2009. This potential pipeline, expected to be operational at the earliest from 2011, will open a new corridor and market outlet for natural gas from the Caspian Sea into Europe. We have chosen to join the TAP project as part of our effort to offer an attractive export route for the Shah Deniz gas to the European market.

Cove Point.

In the US, Statoil Natural Gas LLC (SNG) markets gas to local distribution companies, industrial customers and power generators. LNG will be sourced from our Snøhvit LNG facilities in Norway. Currently, the LNG is imported from Trinidad, Algeria and Egypt and regasified through the Cove Point terminal in Maryland, US. 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 terminal and pipeline. The terminal and pipeline interconnect 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. 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.

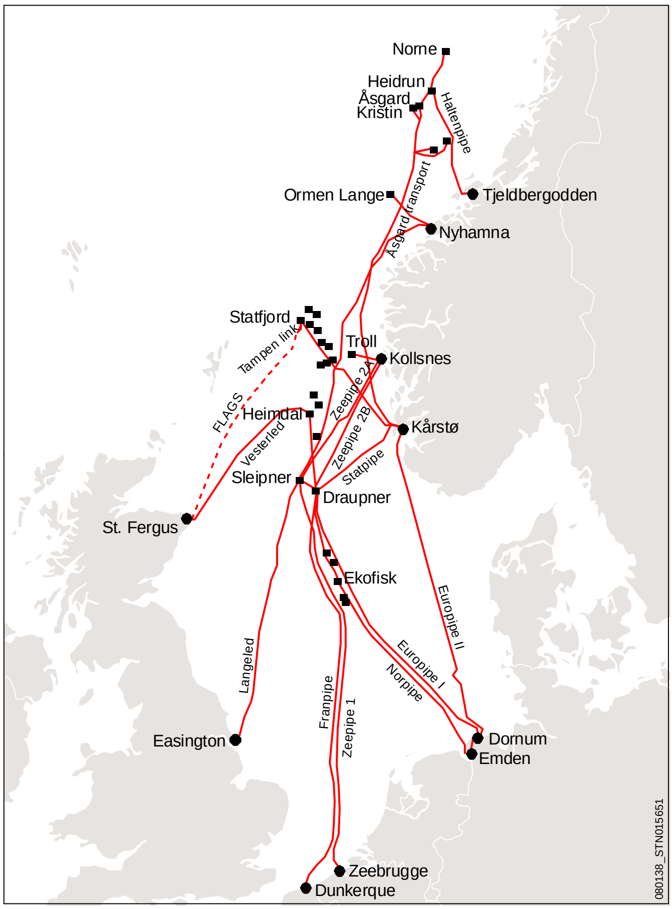
In 2005, StatoilHydro entered into contractual commitments with Dominion for 100% of the expansion of the Cove Point terminal with a capacity of approximate 7.7 bcm annually of gas for a 20-year period, with planned start-up in late 2008 or early 2009. The expansion reflects our focus on the growing 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, the additional 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.

Arctic Princess. In 2007 Arctic Princess was the first vessel to leave port at Melkøya with LNG from the Snøhvit field

On 20 October 2007, the first vessel with a cargo of liquefied natural gas from the Snøhvit field left port at Melkøya. For the first time StatoilHydro is supplying gas from the Norwegian continental shelf in a cooled state by ship. LNG gives us increased flexibility in terms of marketing gas globally. The plant at Melkøya is the first LNG production facility in Europe and it will be a key component in StatoilHydro's focus on LNG, which is the fastest growing gas market in the world. The LNG plant has suffered from operational challenges and there are still uncertainties related to the timing of regular and stable operations. Our 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.

3.3.4 Norwegian gas transportation system and other facilities



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

To transport Norwegian natural gas to European customers, Norwegian gas producers have built an extensive gas pipeline system, connecting gas fields to gas processing plants on the Norwegian mainland and receiving terminals in Europe.

In 2003, all gas pipelines with third party access were unitised into a single joint venture, Gassled. The Gassled system is operated by Gassco AS, which is wholly owned by the Norwegian State. Gassco has no ownership interest in Gassled or in gas production. In 2007, the Gassled system transported 86.3 bcm (3.0 tcf) of Norwegian gas and it has additional capacity to transport 35 bcm to 40 bcm (1.2 tcf to 1.4 tcf) per year. Our ownership in Gassled and other pipelines and terminals is listed in the tables below.

The Kårstø Expansion Project and Langeled were included in Gassled with effect from 1 October 2005 and 1 September 2006, respectively. Tampen Link was included in Gassled from 1 September 2007 with subsequent adjustments in Gassled ownership interests.

From 1 January 2011, our ownership interest in Gassled will be reduced due to an increased ownership interest for the SDFI. Similar adjustments of the ownership interest in Zeepipe Terminal JV and Dunkerque Terminal DA will also be made. In addition, our ownership interest in Gassled may change as a result of including existing or new infrastructure or if Gassled undertakes further investments without participation from its owners in proportion with their ownership interests in Gassled. Gassled has a licence period that extends to 2028.

From 1 July 2007, Gassco also took over direct operation of the receiving terminals and the metering stations in Emden and Dornum in Germany, as well as the Zeepipe Terminal and the Dunkerque Terminal. Prior to 1 July 2007, the facilities in Emden and Dornum were operated by a joint operating company established by StatoilHydro and ConocoPhillips. At the time Gassco took over operations of these facilities, roughly 100 employees at these facilities were transferred from StatoilHydro and ConocoPhillips to Gassco. It was resolved in 2006 that Gassco, as operator of the Norwegian gas pipeline network, should take over the daily technical operations of the continental terminals.

Langeled passes Sleipner. Sleipner is a hub in the Norwegian gas machine. The latest addition is Langeled and the picture was taken during the pipelying process

The Ormen Lange field was officially opened in October 2007. Gas from the Ormen Lange field is transported in the Langeled pipeline from Nyhamna, via Sleipner to Easington in the UK. At plateau levels, the Ormen Lange field is expected to provide StatoilHydro with more than 6 billion standard cubic meters of gas per year. It is anticipated that Ormen Lange as a field will account for approximately 20% of Norwegian gas export in 2010. The Langeled pipeline is merged with the Gassled system. StatoilHydro was development operator for the Ormen Lange field while Shell took over as field operator 1 December 2007, in accordance with the decision made by the Norwegian Ministry of Petroleum and Energy in December 1999.

In October 2007, the strategically important Tampen Link pipeline was opened. The Tampen Link opens a new corridor to the UK gas market. The Tampen Link pipeline ties Statfjord into Britain's existing Far North Liquids and Associated Gas System (Flags), which runs to St. Fergus in Scotland. The pipeline increases our ability to export gas from the NCS, with a maximum committable capacity of 26.5 million standard cubic metres per day. On completion, the ownership of Tampen Link was merged with Gassled.

Our ability to transport own supply of natural gas from various field interests enables us to make regular and reliable gas deliveries to our customers. The pipelines intersect at platforms, tie-in locations and processing plants, providing a flexible network for the transportation of natural gas from various fields and gas processing plants to our entry points into the European market, depending on our customers' contracted daily and annual natural gas sales requirements. Each field operates with an accounting system, permitting fields to borrow and repay gas volumes as needed to meet their supply needs.

The major costs associated with running a pipeline system are maintenance and compression costs that result from operating compression facilities to support gas throughput. Most transport agreements are based on a tariff per unit transported which covers the operating cost of the transport system and provides a return on the capital invested. The Ministry of Petroleum and Energy sets such tariffs. The pipelines are maintained under an annual maintenance plan approved by the Norwegian Petroleum Directorate.

The following table shows the major NCS gas transportation systems in which we have an interest, and the transportation routes and capacities. All of the pipelines and terminals are operated by Gassco AS.

Gas pipelines not included in Gassled	**Start up date**	**Product**	**Start point**	**End point**	**Transport capacity 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 I	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 Kårstø	Draupner S Draupner S	33.3 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)	

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

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

Gas pipelines not included in gassled	Start up date	Product	Start point	End point	Transport capacity mmcm/day	StatoilHydro share in %
Norne Gas Transportation System	2001	Rich gas	Norne field	Åsgard Transport	11.0	39.10
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
Kvitebjørn gas pipeline	2004	Rich gas	Kvitebjørn	Kollsnes	25.4	58.55

Terminal facilities included in Gassled	Startup 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

Terminals not included in Gassled	Startup date	Product	Location
Zeepipe terminal JV (1)	1993	Dry gas	Zeebrugge, Belgium
Dunkerque terminal DA (2)	1998	Dry gas	Dunkerque, France
Etanor DA	2000	Ethane	Kårstø, Norway

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

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

Ownership structure Gassled	Period 2006-2007(1)	Period 2007-2010(1)	Period 2011-2028
Petoro AS (2)	38.25%	37.89%	46.23%
StatoilHydro ASA	31.80%	32.06%	28.05%
Total	8.09%	8.00%	6.21%
ExxonMobil	9.57%	9.66%	8.26%
Shell	5.26%	5.33%	4.92%
Norsea Gas AS	2.84%	2.81%	2.33%
ConocoPhillips	1.95%	2.02%	1.69%
Eni	1.57%	1.56%	1.31%
Dong Energy	0.69%	0.68%	1.04%
StatoilHydro interest including 28.58% of Norsea Gas AS	33.32%	32.86%	28.72%

(1) Change effective dates 1 September 2006 and 1 September 2007. The changes are due to inclusion of the new pipelines Langeled and Tampen Link respectively.

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

3.3.5 Kårstø gas treatment plant

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

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 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. Products produced at Kårstø include ethane, propane, iso-butane, normal butane and naphtha and stabilised condensate. The treatment plant currently has a design 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 a common term 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. Plans call for the completion of KEP2010 projects between 2010 and 2012, with upgrading work beginning in 2008. The KEP2010 workforce working on site will comprise around 500 personnel at any given time. In 2007, Kårstø produced 0.9 million tonnes of ethane, 4.6 million tonnes of LPG and 2.8 million tonnes of condensate/naphtha exported to customers worldwide.

3.3.6 Kollsnes gas treatment plant

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

As TSP, StatoilHydro is responsible for the operation, maintenance and further development of the Kollsnes gas treatment plant on behalf of the operator Gassco. The plant was built to receive gas landed from the Troll field through two 36-inch pipelines. Kollsnes was upgraded in 2005 to receive gas from Visund and Kvitebjørn. In 2006, a sixth export compressor was put into production, increasing the export capacity by approximately 25 mmcm per day. The plant currently has a design capacity of 146.5 mmcm per day. In 2007, Kollsnes produced 38.5 bcm of dry gas and 1.6 mcm of condensate.

3.3.7 Gas sales agreements

StatoilHydro is required by the Norwegian State to manage, transport and sell the 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 in which 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. Our long-term contracts generally run for 10 to 20 years or more. A significant portion of our current long-term sales contracts will reach plateau level between 2005 and 2008.

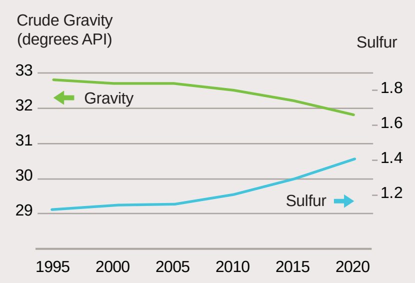
Prices in these contracts are generally tied to a formula based on the prevailing prices for a customer's principal alternative fuels to natural gas, mainly heavy fuel oil and gas oil. Consequently, there can be significant price fluctuations during the life of the contract. Prices in these contracts are generally 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. By contrast, recent long-term gas sales contracts in the UK are priced with reference to a daily UK market gas price index. However, the price formula, which allows for monthly or quarterly adjustment, does not pick up on all trends in the marketplace, i.e. 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 2007, StatoilHydro was involved in commercial discussions (in lieu of price review) or in formal price review processes for approximately 43% of the volumes covered by our long-term sales contracts.

3.4 Manufacturing and Marketing

3.4.1 Industry overview

We expect oil and gas consumption to continue to grow and thereby play a central role in the global demand for energy for at least the next 20 to 30 years. We expect growth in demand in OECD markets to be moderate, while demand from emerging economies will be stronger. We further envisage some challenges globally in bringing upstream capacity on stream on time to meet increased demand. In addition, we expect a decline in production on the NCS, and the expectation is that the global supply situation will remain tight.

CRUDE TOWARDS HEAVIER & HIGHER SULFUR



Source: Hart World Refining and Fuels Service

We believe that future hydrocarbon exploitation will be increasingly complex and costly. The quality of oil produced will vary more as the methods of developing available resources will increasingly become unconventional. At the same time, the quality requirements for end user products will become more stringent. The conversion process is therefore expected to become more challenging. Selective midstream and downstream involvement and presence will thus be important to ensure robust value chains for upstream projects with extra heavy crude oil qualities.

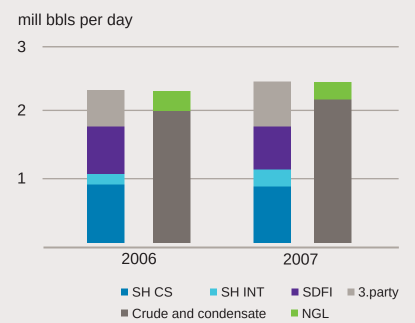
We expect the current focus on the environmental footprint of energy use to continue. As such, there will be focus on non-hydrocarbon transportation fuels. We believe that energy companies that provide solutions to these environmental challenges will improve their competitive position.

Future oil demand will increasingly be focused on the transportation sector, and new energy carriers are expected to emerge in the stationary energy sector. We anticipate that the oil value chain therefore will be increasingly directed towards the transportation fuel segment. Europe has been moving towards an increase in diesel vehicles since the European Commission encouraged lower taxes on diesel fuel. We believe this trend will continue.

The availability of the necessary human resources and competence will also remain a key challenge for the industry in general and even more so for the midstream sector.

3.4.2 Oil Sales, Trading and Supply

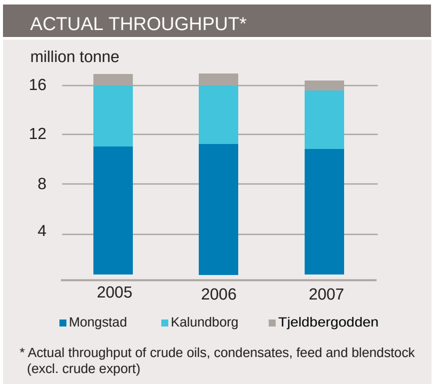
TRADED VOLUMES PER DAY OF OIL



We are one of the largest net sellers of crude oil in the world, operating from sales offices in Stavanger, London, Singapore and Stamford, selling and trading crude oil, NGL and refined products. We market and sell own volumes of crude and NGLs together with the Norwegian State's volumes and third party volumes. In 2007, we sold 783 mmbbl of crude oil and condensate. This includes sales to our own refineries and other internal divisions. The main crude oil market for StatoilHydro is in north-western Europe. However, 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 2007, approximately 47% were StatoilHydro volumes. Total sales of LPG amounted to 8.2 million metric tonnes and total sales of naphtha were 4.4 million metric tonnes in 2007. Most of the LPG and naphtha was sold to customers in north-western Europe.

The main markets for our refined products, NGL and condensate, are in north-western Europe and the Baltic Sea area. We are supplying condensate in Europe, including to our own refineries at Mongstad and Kalundborg, as well as to other refiners and the petrochemical industry. In addition, condensate cargoes are sold in the US market. In 2007, we sold approximately 30 million tonnes of refined oil products, the majority of which were refined at our refineries at Mongstad and Kalundborg. From the fourth quarter of 2007, new condensate grades were available from the Ormen Lange and Snøhvit fields, which gives us more qualities, flexibility and increased trading volumes from the NCS.

3.4.3 Manufacturing



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 right 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.

	For the year ended 31 December											
	Throughput [1]			Distillation capacity [2]			On stream factor % [3]			Utilization rate % [4]		
Refinery	2007	2006	2005	2007	2006	2005	2007	2006	2005	2007	2006	2005
Mongstad	**10.9**	11.2	11.1	**8.7**	8.7	8.7	**97.8**	99.1	98.5	**93.2**	97.9	98.7
Kalundborg	**4.7**	4.9	4.9	**5.5**	5.5	5.5	**96.4**	94.7	97.8	**91.7**	91.0	89.6
Tjeldbergodden	**0.70**	0.89	0.90	**0.95**	0.95	0.95	**81.7**	94.6	99.1	**97.7**	95.6	96.3

(1) Actual throughput of crude oils, condensates, feed and blendstock, measured in million tonnes.
(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

Mongstad.

The Mongstad refinery, built in 1975, significantly expanded and upgraded in the late 1980s and subject to considerable investments over the last 10 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, 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 (up to one million tonnes per year), NGL from Oseberg and Tune, and condensate from Troll, Kvitebjørn and Visund.

Mongstad product yields and feedstock	2007		For the year ended 31 December 2006		2005	
LPG	**373**	**3%**	359	3%	335	3%
Gasoline/naphta	**4,721**	**43%**	4,802	43%	4,647	42%
Jet/kero	**755**	**7%**	801	7%	705	6%
Gasoil	**3,865**	**35%**	4,050	36%	4,247	38%
Fuel oil	**311**	**3%**	302	3%	225	2%
Coke/sulfur	**222**	**2%**	231	2%	239	2%
Fuel, flare and loss	**692**	**6%**	620	6%	694	6%
Total throughput	**10,939**	**100%**	11,165	100%	11,092	100%
North Sea crude oils						
Troll, Heidrun (FOB crude oils)	**4,751**	**43%**	5,508	49%	4,999	45%
Other North Sea crude oils (CIF crude oil)	**3,780**	**35%**	2,616	23%	3,336	30%
Residue	**1,265**	**12%**	1,324	12%	1,256	11%
Other fuel and blendstock	**1,143**	**10%**	1,718	15%	1,501	14%
Total feedstocks	**10,939**	**100%**	11,165	100%	11,092	100%

The Mongstad refinery is able to manufacture products to meet different specifications through its in-line blending during ship loading. Considerable investments have been made in the last 10 years to meet new product specifications.

The refinery reliability (i.e. on stream factor) was high in 2005, 2006 and 2007. There were no planned turnarounds in 2005, 2006 or 2007. We are planning a major turnaround in 2008.

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

The CHP plant is a strategically important project for Manufacturing & Marketing. The use of heat from the CHP plant will result in significant improvements in 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 when it comes online in 2010. The plant will be built and operated by Dong Energy, and StatoilHydro will pay an annual fee for use. By year end 2007, the progress of the CHP investment project was 31%, as planned. Under an agreement with the Troll licensees, this facility will also supply power to the Troll A gas platform and the associated Kollsnes processing plant onshore. In addition to the CHP plant, the project includes a new gas pipeline from Kollsnes and necessary modifications at the refinery.

StatoilHydro and the Ministry of Petroleum and Energy have agreed to form a technology company that will facilitate the building of a carbon dioxide capture plant at Mongstad. We will own 20% of the company. The plant will have a capacity to capture 100,000 tonnes of carbon dioxide annually. The goal is to test, qualify and develop carbon capture technology in order to reduce costs and risk. Due to the test nature of the facility and the current lack of infrastructure for transportation and storage, the carbon dioxide will not be stored until later. Based on the lessons learned, a final investment decision is planned in 2012 to build a full-scale capture plant at the refinery. The Norwegian State has full responsibility for the investment in and operation of this full-scale carbon capture plant.

3.4.3.2 Kalundborg

Kalundborg.

Kalundborg produces products such as gasoline, jet fuel, diesel oil, propane and fuel oil, supplying markets in Denmark and Sweden. 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 European, 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.

Kalundborg product yields and feedstock	For the year ended 31 December 2007		2006		2005	
LPG	**78**	**2%**	96	2%	95	2%
Gasoline/naphtha	**1,475**	**31%**	1,495	30%	1,537	31%
Jet/kero	**209**	**4%**	259	5%	236	5%
Gasoil	**1,997**	**42%**	2,042	42%	2,018	41%
Fuel oil	**746**	**16%**	775	16%	792	16%
Coke/sulfur	**5**	**0%**	5	0%	6	0%
Fuel, flare and loss	**185**	**4%**	193	4%	195	4%
RERUN	**23**	**0%**	50	1%	55	1%
Total througput (1)(4)	**4,717**	**100%**	4,915	100%	4,933	100%
North Sea crude oils						
Sleipner, Åsgard (2), other condensates (3)	**170**	**4%**	1,088	22%	1,010	20%
Other North Sea crude oils	**4,371**	**93%**	3,588	73%	3,639	74%
Other fuel and blendstocks	**153**	**3%**	187	4%	216	4%
RERUN	**24**	**1%**	52	1%	68	1%
Total feedstocks	**4,717**	**100%**	4,915	100%	4,933	100%

All notes are for 2007 only.

(1) Includes 23,1 RERUN & SLOP (RERUN & SLOP = re-use of (partly) processed material).

(2) Åsgard was re-classified as a crude in 2007, which explains the large redistribution among feedstocks.

(3) Includes 24,4 kt RERUN.

(4) Due to both a turn-around in the Cruderefinery and a regenerartion in the Condensate Plant the hroughput (i.e. volumes) were lower than previous years.

There were turnarounds in both 2005 and 2007.

Kalundborg is a plant with high energy efficiency, high utilisation and relatively low operating costs. The refinery has improved its performance substantially 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 main project at Kalundborg in 2007 has been the Fuel Reduction Project. This project is expected to be on stream March 2008, and will reduce production of heavy fuel oil and increase sulphur free auto diesel.

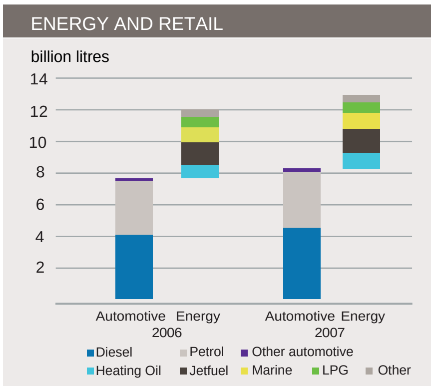
3.4.3.3 Tjeldbergodden

Tjeldbergodden.

Our methanol operations at Tjeldbergodden in Norway, which we own 81.7%, have a maximum proven capacity of 0.92 mmtpa and the actual throughput in 2007 was 0.70 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 industrial gases produced.

3.4.4 Energy and Retail



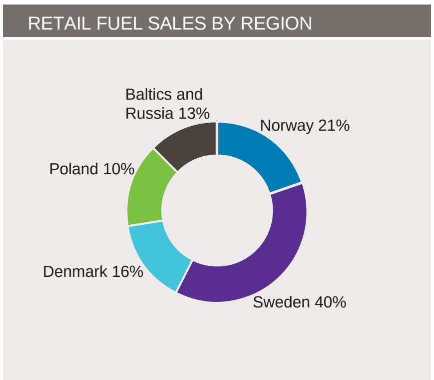
Energy and Retail has approximately 9,600 employees, and consists of approx 2,300 service stations and 185 truck stops in 8 countries. In addition, we are marketing refined products to consumer and industrial markets.

The Energy segment supplies aviation and marine fuels, as well as a large number of Statoil-brand refined products. These 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, which is based on approximately 350,000 customers and annual sales of approximately 4.7 billion litres. In the LPG market, we have a market share of approximately 40% of the Scandinavian market. Our portfolio also includes ownership interests in gas distribution companies.

The full-service stations in the Retail segment provide automotive fuels, car accessories and simple vehicle service products. In addition, most stations offer consumer goods, including fast food, convenience products and basic groceries. In 2007, these stations, together with automated stations, sold approximately 5.3 billion litres of petrol and diesel. Bulk fuel sales and sales from truck stops accounted for additional sales of three billion litres.

The following table lists these retail outlets by region or country as of 31 December 2007 and our volume of automotive fuel sales for the year ended 31 December 2007:

Retail outlets/country	Scandinavia	Poland	Baltics	Russia	Total
StatoilHydro owned and operated	277	183	159	8	**627**
StatoilHydro owned and dealer operated	614	0	1	0	**615**
Dealer owned and StatoilHydro operated	0	0	0	0	**0**
Dealer owned and operated	535	31	9	0	**575**
Automated stations	426	32	17	0	**475**
Total	1,852	246	186	8	**2,292**
Truck Stops	185	0	0	0	**185**
Automotive fuel volumes (million litre)					
Petrol	2,652	341	515	29	**3,537**
Diesel	3,719	339	511	3	**4,572**
LPG/ethanol	43	126	33	0	**202**
Total	6,414	806	1,059	32	**8,311**



Scandinavia is our home retail market. We have a petrol market share of approximately 30% in Norway and 17% in Denmark. In Sweden our Statoil and Hydro branded stations have a petrol market share of approximately 32%. 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 40% and 32%, respectively, of the local retail petrol market in 2007.

During 2007, the retail network and energy business in the Faeroe Islands was sold resulting in a capital gain of approximately NOK 0.1 billion after tax.

3.5 Technology and New Energy

3.5.1 Industry overview

The success of our business is closely related to our access to and application of advanced technological expertise, which has largely been developed through exploration and production activities on the NCS. Many major challenges have been addressed, including operating under the harsh weather and environmentally sensitive conditions in the Norwegian Sea, transporting oil and gas across the deep Norwegian trench, and draining complex petroleum reservoirs characterized by high pressures and high temperatures. Much of this experience is increasingly being applied to StatoilHydro's international operations.

In the wake of higher energy prices, technology development has intensified in both the oil and gas industry and in the field of renewables.

The renewable energy industry is growing rapidly, driven by ambitions to increase the contribution of sustainable energy to the total energy supply. Although energy production from renewables is still modest in most countries, wind power, solar energy and bio fuels are developing into significant industries. Global investment in sustainable energy has seen double digit growth rates in recent years.

3.5.2 Technology development

StatoilHydro is the world's largest operator of offshore fields in water depths below 100 metres, and we have considerable experience of 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 a 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 heading up established corporate initiatives in order to improve performance in exploration, increased oil recovery 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 during the last few years are summarised below.

Exploration
As the competition for prime acreage intensifies, so does the need for better exploration concepts, methods and tools.

Much progress has been made in the geological understanding and geophysical imaging of Atlantic margin deepwater plays and prospects, including those occurring beneath thick layers of salt. Advances are also being made in extending electromagnetic seabed logging from 2D to 3D and combining seabed logging with seabed seismic surveys. Both techniques are designed to lower the risk of dry holes by differentiating between petroleum and water-bearing prospects prior to drilling. Another innovation is the development of a disposable rig-less exploration tool, which burrows its way down to a prospect. This development may assist in obtaining low-cost, real-time geological information in advance of drilling.

Other advances have been made in increasing the speed with which high-quality subsurface seismic images can be produced and improving our fundamental understanding of geological processes to rapidly screen prospective basins. The accurate assessment of the maturation, migration and entrapment of hydrocarbons around the world is of paramount importance in identifying prospective areas.

Increased Oil Recovery (IOR)
We are also achieving some of the petroleum industry's highest reservoir recovery factors on the NCS by combining geoscientific and engineering capabilities and boldly introducing new technology. We have already increased hydrocarbon production from a number of NCS fields (e.g. Gullfaks) using conventional time-lapse 4D seismic - a technology in which we are an industry leader - and we have come far in terms of developing a 4D seabed seismic monitoring system (with Optoplan) based on fibre optic technology. The latter is expected to result in better data capture and resolution during a field's productive lifetime. Besides having "4D data on demand", fibre optic systems promise to be less expensive than their counterparts and largely remove the risk of failure when using electronic sensors and cables.

Other IOR advances are being made in drilling and well technology. For example, "through-tubing drilling and completion" technology permits offshoot wells (sidetracks) to be drilled laterally from their parents in order to access isolated pockets of untapped oil and gas in mature fields. Optimal directional well positioning permits the penetration of more distant parts of a reservoir and the drilling of production wells that do not follow simple paths. Moreover, the completion and remote control of smart wells (including multi-laterals) helps to increase ultimate recovery factors.

Subsea field development and long-distance transport
We are the leading company in subsea field development and the second largest in terms of subsea wells. We are also witnessing a gradual transition from topside to seabed facilities, both on the NCS and internationally. These advances should facilitate ultra-deepwater field developments and pave the way for Arctic operations, when coupled with long-distance multiphase transport and pressure boosting.

In 2007, we reached three subsea development milestones: the start of production on the Ormen Lange and Snøhvit fields and the installation of the first full-scale subsea separation facility at Tordis, making it the world's first commercial field with seabed processing. Removing produced sand and water from the Tordis wellstream and re-injecting it into the subsurface is expected to improve the recovery factor from 49% to 55%.

The Ormen Lange and Snøhvit developments have also broken records in terms of long-distance transport. Unprocessed wellstream is carried 160 kilometres from the furthest Snøhvit well to the LNG plant near Hammerfest, while the world's longest subsea pipeline, Langeled, carries Ormen Lange gas from central Norway to the UK over a distance of 1,200 kilometres. We were responsible for the design and installation of Langeled, which was laid on time and at cost.

While the offshore part of the Snøhvit project has been a success, the onshore part of this LNG project has experienced some operational challenges and there are still uncertainties related to the timing of regular and stable operations.

Gas solutions
Besides the start-up of the Snøhvit LNG plant, we have completed a specification for larger LNG trains using our proprietary mixed fluid cascade liquefaction process (MFC©). Progress is also being made on the design of an offshore floating LNG plant for developing gas fields that cannot be easily or economically exploited using conventional offshore technology.

StatoilHydro, in association with its partners PetroSA and Lurgi, has developed its own GTL process technology, which is currently being demonstrated in a semi-commercial plant at Mossel bay in South Africa.

Carbon capture at Mongstad
Turning to carbon management, the Norwegian state and StatoilHydro have reached agreement on the construction of a full-scale carbon capture plant at our Mongstad refinery. The first development stage, capable of capturing 100,000 tonnes of carbon dioxide annually, is scheduled to for completion in 2011, one year after the start-up of the planned combined heat and power plant (CHP). This stage consists of a carbon dioxide test centre partnered by StatoilHydro, Dong Energy, Vattenfall, Shell and Gassnova SF. The second stage will involve a full-scale facility capable of capturing carbon dioxide from both the CHP plant and other appropriate emission sources at or around the refinery.

The establishment of the European carbon dioxide test centre at Mongstad has the following objectives:

- To demonstrate/qualify and scale-up high-risk technologies / technology improvements in post-combustion carbon capture (Carbonate).
- To make incremental technology improvements in a generic and flexible amine test unit.
- To build knowledge among the partners with a view to full-scale project realisation (equipment, solutions and results should be fully up-scalable).
- To build a test plant for carbon capture technology applicable to both gas and coal-fired power stations, balancing and taking into account the needs (application, geography) of the individual partners.
- To measure and compare test results with reference cases to achieve strategic ambitions.
- To build and share knowledge and competence concerning carbon capture technology between the partners.
- To provide knowledge about the capabilities and develop good relations with vendors of carbon capture technology.

New Energy
Technology development in New Energy aims to support the long-term strategy, while short-term business growth is primarily based on the application of existing technology. In wind power, the main development focus is on windmills for offshore applications. Our Hywind floating wind mill technology has been successfully model-tested and this 2.3 MW unit is scheduled for operation off the west coast of Norway from late 2009.

Complementary offshore wind technologies are available through our equity positions in the Norwegian companies Sway AS and ChapDrive AS.

We have an interest in developing operational wind power through our holding in Arctic Wind, which operates the Havøygavlen wind farm in Northern Norway, which produced 76.5 GWh in 2007.

Looking ahead to possible future processes for synthetic ("second generation") bio fuels, StatoilHydro has completed a technology assessment of forest biomass-to-liquids (BTL) processes. The study, carried out in collaboration with Norske Skog ASA, has been completed and will form the basis for further evaluations of BTL technologies.

In 2007, StatoilHydro acquired a 42.5% holding in the Mestilla biodiesel production plant in Lithuania, with a sales and distribution agreement for the entire biodiesel production capacity of 100,000 tonnes per year. Production started towards the end of 2007. Testing of hydrogen as a future transportation fuel was taken a step further by the opening of our second hydrogen refuelling station in Porsgrunn in Norway.

Hydrogen, itself a long-term option, is also the basis for ongoing sales of water electrolysis technology, in which StatoilHydro holds a strong market position. Product development based on our electrolyser technology continues, aiming at emerging markets for on-site hydrogen generation based on renewable energy.

Through New Energy's investment and venture activities, we have gained insight into technologies at the forefront of wave power, tidal power and fuel cell development.

StatoilHydro's 2008 R&D portfolio

Our 2008 R&D portfolio has been re-structured into five programmes, which corresponds to the technology strategy:

- Explore (global screening techniques for rapidly identifying prospective basins; better geophysical imaging in complex geological settings (e.g. below salt); prediction and identification of deepwater plays; petroleum systems analysis).
- Increased oil recovery (geophysical identification of remaining oil; improved reservoir models and recovery processes; autonomous well management and new drilling concepts).
- New development solutions (production from low-pressure fields; subsea field development and long-distance flow assurance; technology for offshore heavy oil processing and transport).
- Oil and gas value chains (the next generation of LNG plants; unconventional oil and gas processing; pipeline solutions for deepwater and Arctic areas; improved thermal recovery of extra heavy oil).
- New energy and new ideas (CCS; renewable energy sources and carriers; HSE management systems; trend-setting technologies).

3.5.3 Research and development

New technology developed and implemented in 2007 contributed in different ways to the group's financial performance. Performance efficiency increased for seismic processing through improved computer tools. Remaining oil identified in the Statfjord formation on the Snorre field using advanced fluvial modelling tools developed by StatoilHydro. Hydrocarbon production from a number of NCS fields (including Gullfaks) increased using conventional time-lapse 4D seismic - a technology in which we are among industry leaders. We also made good progress in developing a 4D seabed seismic monitoring system based on fibre-optic technology.

Research and Development expenditures were NOK1,969 and NOK 1,616 million in 2007 and 2006, respectively. R&D expenditures are partly financed by joint venture partners of StatoilHydro operated activities. Our share of the expenditures have been recognized as expenses.

3.5.3.1 R&D initiatives

As conventional fossil fuels become ever harder to find, companies are increasingly setting their sights on remote geographical areas and developing unconventional hydrocarbon sources such as oil sands and building growth platforms in carbon-free energy sources (renewables).

In exploration technology, we plan to develop new (and in some cases unconventional) basin and prospect concepts, and to continue improving subsurface imaging and interpretation by integrating geophysical and geological methodologies and incorporating them into next generation workflows. 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. An important success factor here is integrated operations, which we define as new work processes that use real-time data to enable closer cooperation between disciplines, organisational entities and geographical areas. The objective is to achieve more reliable, better and swifter decisions.

Innovative offshore field development solutions are largely expected to focus on the exploitation of hydrocarbons in deepwater and Arctic areas, as well as areas containing heavy oil. We foresee an increasing transition from topside to intelligent, remotely-operated, autonomous seabed facilities, coupled with ultra-long, subsea tie-backs and wellstream compression devices. Furthermore, we believe it will be necessary to develop new drilling concepts, especially in ice-infested areas, and to develop pipelines capable of withstanding ultra-cold and ultra-deepwater conditions. We plan to focus on developing onshore extra heavy oil value chains and on improving recovery methods, water management and carbon capture.

The opportunities in gas chain technology may lie in gaining greater access to, and cost-effectively developing, difficult unconventional gas resources and acquiring leading-edge capabilities in selected technologies (such as membrane-based separation). The realisation of floating LNG (and possibly floating GTL) facilities for gas fields that cannot otherwise be easily or economically exploited is another opportunity we plan to pursue. We also plan to develop sustainable CCS value chains.

Our commitment to environmental stewardship is twofold: meeting our zero harm to the environment objective by expanding our toolkit of environmental monitoring and integrated risk-modelling systems and creating business in new energy sources. In addition to consolidating our present activities in offshore wind and bio fuels, we plan to further investigate opportunities in geothermal and solar power and the use of hydrogen as an energy carrier. We believe technological innovation is the key to meeting a profitable, sustainable, low-carbon energy future.

3.6 Projects

3.6.1 Industry overview

On the NCS, the trend is moving from a portfolio of mainly green-field and tie-in projects towards complex, brown-field redevelopment projects on old installations, where vital work must be timed to coincide with major planned turnarounds.

Because of the growing portfolio and the fact that the market situation requires more internal resources to ensure deliveries of acceptable quality at the right time, the shortage of engineering competence is as critical as in previous years, with respect to both the number of available engineering personnel and the competence and quality of work delivered. In addition, increased international activity is expected to make strong demands on our ability to utilise our resources to develop international activities. In consequence, there is a risk that engineering may be negatively affected, which, in turn, may influence construction and completion progress.

To develop a global mindset in our organisation, we must create and mobilise the right teams in regions and areas where we have little or limited experience.

A high activity level on the NCS will make strong demands on our ability to execute projects as sanctioned and in accordance with our 'zero harm' HSE vision. 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, there have been significant cost increases and this remains a concern. The tight market can also contribute negatively to the quality of work and deliveries as well as to increased lead times for deliveries.

3.6.2 Projects development

A number of new projects will require our attention in the coming years. The Gjøa/ Vega development, Tyrihans, Morvin, Alve and Yttergryta are all examples of new projects on the NCS that are expected to contribute to continued growth on the NCS, whereas Ormen Lange Offshore and Statfjord Late Life are two projects that are expected to contribute to optimising production from existing assets.

Project completions 2008 - 2009	**Type**
Volve	Offshore NCS
Oseberg Delta	Offshore NCS
Alve	Offshore NCS
Yttergryta	Offshore NCS
Tyrihans	Offshore NCS
Troll O2 Template	Offshore NCS
Heidrun Drilling Unit Upgrade	Modifications NCS
Tune Low Pressure Production	Modifications NCS
Sleipner B Compression	Modifications NCS
Statfjord C to Vigdis Water Injection	Modifications NCS
Troll C Low Pressure Production	Modifications NCS
Heimdal New Power generator	Modifications NCS
Brage Produced Water Re-injection	Modifications NCS
Snorre A redevelopment improved oil recovery (IOR)	Modifications NCS
Statfjord Late Life	Modifications NCS
Tampen Link	Onshore
Kollsnes Flash Gas and Condensate (KFGC)	Onshore
NOx Mongstad	Onshore
Energiverk Mongstad (EVM)	Onshore
Receiving terminal for LNG to Oslo	Onshore
South Pars Phase 6-8 (all phases)	International
InSalah Gas Compression	International
Hywind Demo	New energy

Internationally, we see a number of projects that supports our global ambitions. However, to become a truly global energy player we must also perform the role of operator. Our contribution in this respect will be to execute projects such as South Pars, In Salah and Leismer in a predictable manner. By reaching the major milestones in these projects on schedule and while maintaining high HSE standards, our reputation as a world-class implementer of projects will be strengthened.

3.6.2.1 Norwegian Continental Shelf

Gjøa.

After the completion of both Snøhvit and the Ormen Lange/Langeled developments, the combined **Gjøa/Vega** development is the largest ongoing project on the NCS. Over a period of four years, NOK 37 billion is expected to be invested in these projects, located in the Sogn-area off the west coast of Norway. The Gjøa producing facility is designed in a way that makes it possible to process oil and gas from other small discoveries in the area in the future.

The Gjøa-platform will be provided with land-based electricity from Mongstad that is estimate to reduce emissions by 240,000 tonnes of carbon dioxide per year, equivalent to the annual emissions from 100,000 cars.

Tyrihans is a NOK 14.5 billion 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.

All major contracts (pipeline, subsea production system, drilling rig, drilling services and well completion equipment) are awarded, and as of November 2007, the project is progressing in accordance with plans.

During the 2008 and 2009 seasons, marine operations will be conducted, including installation, tie-in and RFO. The remaining work prior to the estimated start-up in July 2009 consists of topside modifications on Kristin and Åsgard B and delivery of the subsea production system and seawater injection system.

The **Alve** discovery is developed with one subsea template as a satellite tieback to the Norne FPSO, optimising the capacity at Norne. The investment related to developing Alve is NOK 2.5 billion, and production is estimated to start up during the first quarter of 2009.

The concept includes a four-slot HOST template at Alve with an umbilical and a 12,6" ID insulated production pipeline with direct electric heating (DEH) for hydrate control to Norne. The gas will be processed at Norne. Some modifications topside are necessary to include well stream from Alve. The Alve development solution includes some flexibility for future additional tie-backs.

The **Yttergryta** subsea gas and condensate field development with an expected capital expenditure value of approximately NOK 1.2 billion is an excellent example of a relatively small but unique project in our portfolio. The discovery was made in the summer of 2007, and production start-up is expected to take place in 2009. The wellstream will be 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. The purpose 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 development of the Ormen Lange field in the Norwegian Sea is one of the largest and most demanding industrial projects ever carried out in Norway. StatoilHydro has been operator during the development phase of Ormen Lange, and the operatorship was handed over to Shell in December 2007 after production start-up in October 2007.

The field has been developed with seabed installations at depths down to 1,100 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, 1,200 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.

The development of Ormen Lange has been challenging. Pipelines and installations had to be placed on the extremely steep and uneven area of the sea floor where the Storegga Slide took place 8,000 years ago.

The subsea installations have to be able to withstand the exceptional currents that are characteristic of this part of the Norwegian Sea, as well as sub-zero temperatures on the sea floor, and extreme wind and wave conditions.

Following a gradual increase in production over the first two to three years, the field is expected to produce 70 million standard cubic meters of gas per 24-hour period.

3.6.2.2 Onshore facilities

Kårstø Expansion.

A large redevelopment programme is currently underway at the Kårstø, Mongstad and Kollsnes production sites. A total of almost NOK 12 billion is currently being invested to ensure the regularity of gas production and to prepare for future volumes from sanctioned projects offshore.

At Mongstad, the project for the construction of a CHP plant is well underway. When in operation in 2010, the CHP is expected to increase the energy efficiency at Mongstad to close to 80% and make the Mongstad processing facility self-sufficient in power, in addition to supplying power to Troll A, Gjøa and Kollsnes. The capacity will be about 280 megawatts of electricity and roughly 350 megawatts in the form of heat from this combined heat and power plant at Mongstad.

At Kårstø, several smaller projects have been gathered together in the Kårstø Expansion Project 2010 (KEP 2010). The first part is a compressor upgrade that will make it possible to increase the pressure, and thus enable more stability in the gas flow through the export pipelines leaving Kårstø. The second part of the project is a complete modernisation and upgrading of security and control systems at the site, to prepare the plant for several more years of production and to meet stricter future HSE standards.

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 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 will be built into the systems.

3.6.2.3 International

South Pars.

On 12 December 2002, we became operator for the development of the offshore part of the **South Pars phases 6-7-8** project . The South Pars phases 6-7-8 offshore project consists 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.

Together with the SPD 7 tripods and flare tower, the SPD 9 platform topside was installed offshore during the spring of 2007. We are presently completing the SPD 9 platform for production start-up in 2008 and are preparing SPD 7 and SPD 8 for onshore mechanical completion followed by offshore installation and production start-up during 2008 and 2009. Planning for the installation of the third pipeline is progressing. Project completion is estimated for 2009.

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 to 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.

Executing projects in completely new surroundings like Algeria presents us with a lot of new challenges. Standards with respect to safety and security are different from what we are used to, and working in a joint venture reveals distinct cultural and company differences with regard to project development.

The project is still in the initial phase and detailed engineering has started.

Through the acquisition of the **North American Oil Sands Corporation**, StatoilHydro gained access to 1,110 square kilometres of oil sand leases situated in the Athabasca region of the Alberta province in Canada, approximately 500 kilometres north-east of Edmonton.

The current development plan is to develop the area through a staged process where the Leismer Demonstration Plant for integrated steam-assisted gravity drainage will be the first stage of a total field development that will have a capacity of 20 mboe per day.

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 accordance with coordinated master plans for the different fields, such as the various redevelopment projects taking place at Statfjord, Troll and Oseberg.

Statfjord Latelife.

On 12 October, gas export started from the Statfjord Field to UK customers through the Tampen Link pipeline. The gas processing facilities that have been installed on the three Statfjord pipelines will enable us to increase the gas recovery rate from 58% to 74%.

In the coming 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.

In the Troll area, a number of redevelopment projects are scheduled for the years to come, both with a view to carrying out required refurbishments and to ensure maximum recovery from the reservoirs (IOR) and increase production efficiency.

The compressor upgrade and extension of the living quarters on Troll A, the low-pressure production on Troll C and the Troll B gas injection are all vital projects in this respect. The total investment involved amounts to more than NOK 5 billion.

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.

The major redevelopment projects on Oseberg amount to a total investment of almost NOK 3.5 billion during the period 2008-2010. Vital projects include low-pressure production on Oseberg F, a heat recovery steam generator on Oseberg F and upgrading of the drilling unit at Oseberg B.

3.7 People and organisation

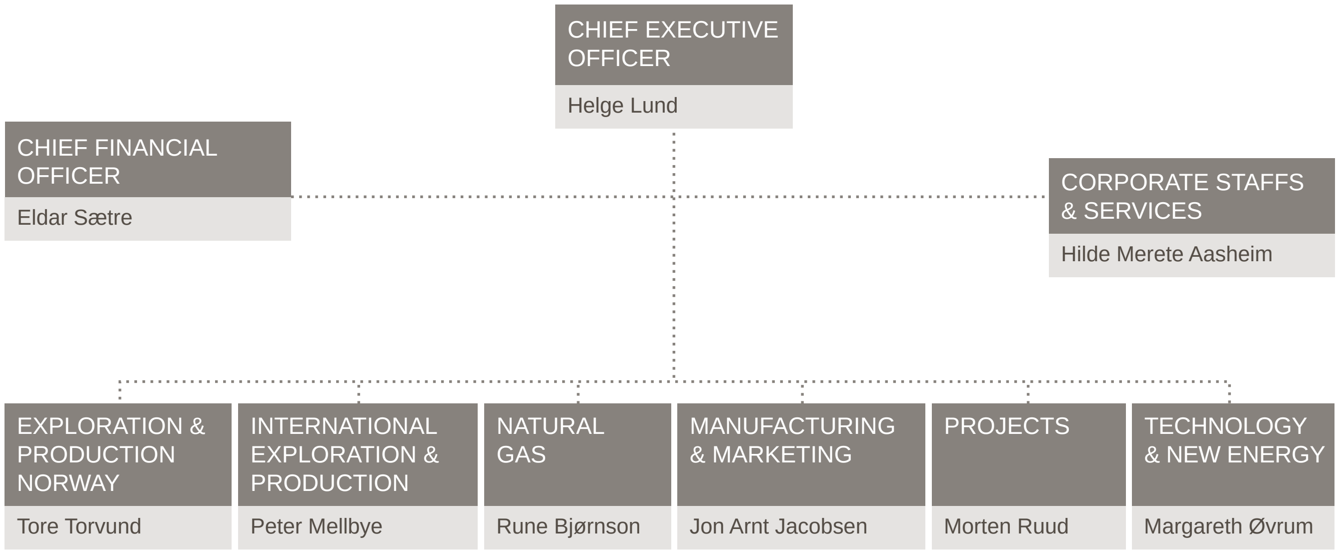
In StatoilHydro, the way in which our results are achieved is as important as the results themselves. We will create value for our owners based on a clear performance framework defined by our values and principles for HSE, ethics and leadership.

Our ambition is to be a globally competitive company. We create a stimulating working environment and provide our people with good opportunities for professional and personal development. We seek to achieve this through developing a strong, value-based performance culture, clear principles for leadership and an effective management and control system. Corporate governance, our values, leadership model, operating model and corporate policies are described in the StatoilHydro Book, which has been made available for all employees in Norwegian and English.

The Merger

The merger between Statoil and Hydro's oil and gas activities gave the new company access to highly qualified personnel. In order to achieve our goals and attain the planned growth, the company must be capable of attracting and retaining talented personnel with the right expertise and strong values in a competitive market. Surveys show that Statoil and Hydro, both individually and after the merger, were among the most preferred employers in Norway in 2007.

Emphasis has been placed on building on the best from both companies and on ensuring equal opportunities for all employees. The development of a common corporate culture has been given high priority. Furthermore, policies with respect to compensation and working conditions in the merged businesses have been harmonised in cooperation with employee representatives.



3.7.1 Employees in StatoilHydro

At the end of 2007, StatoilHydro had 29,500 employees, of which 11,000 work outside Norway. The merger resulted in almost 5,000 employees being transferred from Hydro to StatoilHydro. Between February and September 2007, an extensive staffing process was carried out. This gave the company the option of selecting the best for the job and the individual employees a good opportunity to influence their choice of a new job in the merged company.

StatoilHydro is an expertise-based company in which 55% of employees in the parent company have college or university education, and 21% have craft certificates.

StatoilHydro ASA is Norway's biggest company for apprentices and our training of skilled workers maintains a stable and high level. Since the merger, the number of apprentices has increased to 316, spread over the different discipline areas.

3.7.2 Gender equality and diversity

Forty percent of the members of StatoilHydro ASA's new board are women.

Gender equality is an important part of our personnel policy. After the merger, the proportion of female employees in the group is 35%. The proportion of female managers is 26%. Among managers under the age of 45, the proportion of women is 34%.

Women are relatively well represented in the technical disciplines. In 2007, 22% of our staff engineers were women. Among staff engineers with up to 20 years' experience, the proportion of women was 33%. Wage levels are roughly the same for women and men with similar experience and corresponding positions.

The proportion of our skilled workers who are women is 18%. On average, female skilled workers have slightly lower basic salaries than male skilled workers. This is due to differences in jobs and in number of years' experience.

In the group as a whole, women earn 91% of men's earnings. This is due to differences in experience and in the proportion of women and men at different levels in the organisation.

One of the measures introduced to meet our long-term recruitment needs and ensure access to personnel with different experience and backgrounds is the group trainee programme. We received a total of 2,000 applications for the programme from 91 different countries in 2007. The selection of candidates was completed in February 2008.

Share of women in different groups in StatoilHydro in 2007:

- 40% women on the board of StatoilHydro ASA
- 26% of managerial positions in the StatoilHydro group
- 35% of the workforce in the StatoilHydro group
- 28% of apprentices in StatoilHydro ASA

3.7.3 Flexible work arrangements

We have arrangements such as flexible working hours and remote work if the nature of the work is such that this is possible without it having particularly detrimental effects for the company. Such arrangements have become more widespread after the merger as a result of the decision to largely maintain geographical locations from both companies.

As a result of the merger, approximately 300 employees signed commuting agreements with the company and a corresponding number moved to new office locations.

3.7.4 Cooperation with unions

In StatoilHydro ASA, 69% of the employees are covered by collective agreements.

During the merger process, union members from Statoil and Hydro were represented on the Integration Planning Team which, among other things, was responsible for developing the new organisation and designing the staffing process. The climate of cooperation has been good and the process enjoyed broad support among employees.

The company finds it essential to have a good and confidence-based relationship to its employees and their representatives.

3.7.5 Development and rewards

In 2008, all StatoilHydro employees will be included in the annual individual development process, People@StatoilHydro. The process is intended to ensure alignment between the company's business goals and the goals of individual employees. In addition, it is also intended to support the development of our employees and provide a clear picture of their performance and potential. Employees in StatoilHydro ASA are rewarded in relation to their position, expertise, performance and behaviour.

In management development, the focus has been on the start-up of the new management teams. A shared understanding of the business challenges, the company's values and the leadership principles has been an important theme. At year end 2007, more than 100 management teams had completed a structured process. The goal for 2008 is to complete this process throughout the organisation. Work has started on further developing the management development programme.

A separate programme has been established for the training of project managers in cooperation with the University of California, Berkeley.

A broad spectrum of learning programmes is offered through the StatoilHydro School of Business and Technology. Most of them are open to all employees in the company. In 2007, 6,225 courses were completed with a total of 53,067 participants. The total number of hours of tuition was 107,276. As part of the merger process, a number of courses were held in the fourth quarter 2007 in connection with the new company's joint systems and IT solutions.

3.7.6 Health and working environment

StatoilHydro works systematically to ensure a working environment that promotes job satisfaction and good health. There are risk factors in our business that can entail a health and safety risk, and we must have good systems for managing this risk. This is done through defining requirements when we design workplaces. We closely monitor physical, chemical and organisational factors in the working environment, and we have a system for following up groups that are exposed to risk. Special attention is devoted to chemical health hazards, and, in 2007, action plans were drawn up for the individual business areas.

The psychosocial working environment is important. A good balance must be achieved between work requirements, the opportunity the individual employee has for control and participation and support from colleagues and managers. We are focusing strongly on health and job satisfaction in the integration process. Prior to the merger, emphasis was placed on preparing managers to look after the interests of employees and on improving their insight into human reactions to change. This will be closely followed up in the time ahead.

The company's health service is adapted to suit its activities and to meet requirements in the different countries in which it operates. Medical emergency response capability is established where necessary.

StatoilHydro is an inclusive workplace enterprise. We actively monitor the working environment and make adaptations to prevent sickness absence. In connection with sickness absence, employees are followed up with a view to help them return to work as soon as possible. We are concerned with ensuring that employees have a stimulating working environment and are subject to a good personnel policy in all phases of their professional careers.

Sickness absence in StatoilHydro in 2007 was 3.5%. It has remained stable and low at 3.5% for the last three years. The average sickness absence in Norway in the third quarter of 2007 was 6.0%.

3.7.7 Safety

Safe and efficient operations is our first priority. Our technical safety condition monitoring and the safety behaviour programme have been widely recognized.

Accidents and particular major accidents pose a great threat to our business. Basic understanding of risks and the risk influencing factors are vital for performing safe operations.

The total numbers of serious HSE incidents in our operations were held stable in 2007. The numbers of serious gas leakages on our installations and plants have declined slightly in 2007.

StatoilHydro had three fatal accidents in 2007. In connection with mooring of the LPG vessel "Goodwood" at Mongstad harbour, two members of the crew were hit by a towing line and seriously injured. One of them died in the hospital the same day. A member of the winch crew on the crane barge "Saipem 7000" was hit by a hydraulic hose, fell overboard and drowned at the Tordis Field. A truck driver died after a traffic accident in Sweden.

We firmly believe that all accidents can be prevented and our goal remains zero harm. We place a high focus on continually striving for better safety results in all our business.

In striving for improving our results we are proud to say that our safe behaviour programme now includes 35,000 persons. The fundamental aspects of this programme are the five human safety barriers: correct priorities, compliance with requirements, open dialogue, continuous risk assessment and caring about each other.

In our work to reduce the risk, we use a system for monitoring technical safety conditions. Together with daily focus on safe performance of work operations, this makes us able to systematically work day-by-day to reduce the risk for major accidents. Although we did not achieve our 2007 HSE target we feel that we are on the correct track and will seek improvements in the years to come.

3.7.8 Organisational structure

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

Ownership in certain subsidiaries	Equity interest	Ownership in certain subsidiaries	Equity interest
AS Eesti Statoil	100%	Statoil Nigeria AS	100%
Latvija Statoil SIA	100%	Statoil Nigeria Deep Water AS	100%
Statholding AS	100%	Statoil Nigeria Outer Shelf AS	100%
Statoil AB	100%	Statoil Norge AS	100%
Statoil Angola Block 15 AS	100%	Statoil North Africa Gas AS	100%
Statoil Angola Block 15/06 Award AS	100%	Statoil North Africa Oil AS	100%
Statoil Angola Block 17 AS	100%	Statoil North America Inc.	100%
Statoil Angola AS	100%	Statoil Orient Inc AG	100%
Statoil Apsheron AS	100%	Statoil Pernis Invest AS	100%
Statoil Asia Pacific Pte. Ltd.	100%	StatoilHydro Orinoco AS	100%
Statoil Azerbaijan Alov AS	100%	Statoil Polen Invest AS	100%
Statoil Azerbaijan AS	100%	Statoil Russia AS	100%
Statoil BTC Finance AS	100%	Statoil Sincor AS	100%
Statoil Coordination Center N.V.	100%	Statoil SP Gas AS	100%
Statoil Danmark A/S	100%	Statoil UK Ltd.	100%
Statoil Deutschland GmbH	100%	Statoil Venezuela AS	100%
Statoil do Brasil Ltda	100%	StatoilHydro Petroleum AS	100%
Statoil Exploration Ireland Ltd.	100%	UAB Lietuva Statoil	100%
Statoil Forsikring AS	100%	Statoil Metanol ANS	82%
Statoil Hassi Mouina AS	100%	Mongstad Refining DA	79%
Statoil Innovation AS	100%	Mongstad Terminal DA	65%
Statoil Iran AS	100%	Tjeldbergodden Luftgassfabrikk DA	51%

Voting rights correspond to ownership interests.

3.8 Oil and gas production and sales volumes

The following table sets forth 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.

Production	For the year ended 31 December	
	2007	**2006**
Norway		
Crude oil (mmbbls) [1]	**299**	315
Natural gas (bcf)	**1,230**	1,265
Natural gas (bcm)	**34.8**	35.8
Combined oil and gas (mmboe)	**519**	539
International		
Crude oil (mmbbls) [1]	**92**	70
Natural gas (bcf)	**28**	4
Natural gas (bcm)	**0.8**	0.1
Combined oil and gas (mmboe)	**112**	85
Total		
Crude oil (mmbbls) [1]	**391**	385
Natural gas (bcf)	**1,258**	1,269
Natural gas (bcm)	**35.6**	35.9
Combined oil and gas (mmboe)	**632**	624

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

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 licenses, known as the State's direct financial interest, or SDFI, together with our own production. For additional information see section Operational review-Related party transactions. The following table sets forth 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 2007	2006
StatoilHydro: (1)		
Crude oil (mmbbls) (2)	395	382
Natural gas (bcf)	1,339	1,333
Natural gas (bcm) (3)	37.9	37.8
Combined oil and gas (mmboe)	633	620
Third party volumes: (4)		
Crude oil (mmbbls) (2)	240	200
Natural gas (bcf)	226	152
Natural gas (bcm) (3)	6.4	4.3
Combined oil and gas (mmboe)	280	227
SDFI assets owned by the Norwegian State (including royalty):		
Crude oil (mmbbls) (2)	235	254
Natural gas (bcf)	1,325	1,170
Natural gas (bcm) (3)	37.5	33.1
Combined oil and gas (mmboe)	471	462
Total:		
Crude oil (mmbbls) (2)	869	836
Natural gas (bcf)	2,890	2,655
Natural gas (bcm) (3)	79.5	73.3
Combined oil and gas (mmboe)	1,384	1,309

(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.

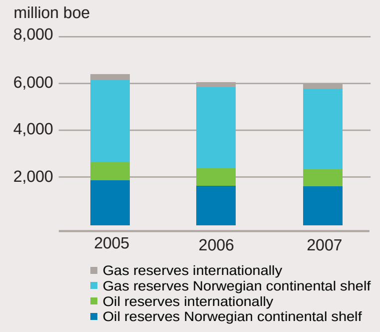
(2) Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.

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

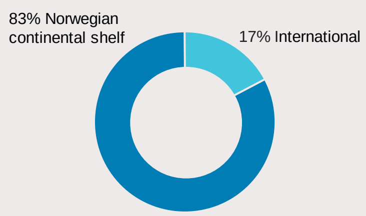
(4) Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG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

3.9 Reserves replacement

PROVED OIL AND GAS RESERVES



DISTRIBUTION OF PROVED RESERVES



Proved oil and gas reserves were estimated to be 6,010 million boe at the end of 2007, compared to 6,101 million boe at the end of 2006.

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.

Changes in proved reserves may also originate from factors outside of management control, such as changes in oil and gas prices. While higher oil and gas prices normally allow more oil and gas to be recovered from the accumulations, StatoilHydro's proved oil and gas reserves under PSAs and similar contracts will generally decrease as a result. This reflects the fact that we will receive smaller quantities of oil and gas under the cost recovery and profit sharing arrangements of these contracts as a result of the increased 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 2007 are expected to be produced in the period from year 2008 to 2026. 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 2007, 2006 and 2005.

	For the year ended 31 December		
Line item (million boe)	**2007**	**2006**	**2005**
Revision and improved recovery	**325**	300	205
Extensions and discoveries	**215**	86	351
Purchase of petroleum-in-place	-	-	72
Sales of petroleum-in-place	-	(3)	(19)
Total reserve additions	**541**	383	609
Production	**(632)**	(624)	(633)
Net change in proved reserves	**(91)**	(241)	(24)

A total of 541 million boe proved reserves were added during 2007, of which 261 million boe were proved developed reserves. The remaining 280 mmboe were proved undeveloped reserves.

The reserves replacement ratio was 86% in 2007, compared to 61% in 2006. The increase in the reserve replacement ratio in 2007 compared to 2006 is mainly due to 2006 being a year with relatively small reserve additions from sanctions of new development projects. The average replacement rate for the last three years was 81%, including purchases and sales.

	For the year ended 31 December		
Reserves replacement ratio (three-year average)	**2007**	**2006**	**2005**
Corporate	**0.81**	0.76	0.92
E&P Norway	**0.78**	0.62	0.77
International E&P	**0.98**	1.74	2.1

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 relating 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 from time to time as new information becomes available. This information can relate 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 relating to proved oil and gas reserves, and other information related to proved oil and gas reserves reported in note 32 - 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 to the responsible management of the relevant business units and the Chief Executive Officer for approval, this central group asks DeGolyer and MacNaughton, independent petroleum engineering consultants, to perform an independent evaluation of proved reserves, which was last performed as of 31 December 2007 for our assets.

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 has delivered to us its summary letter report describing its procedures and conclusions, a copy of which appears 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, often positive, but also 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 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 32 - Supplementary oil and gas information - to our Consolidated Financial Statements, for further details of our proved reserves.

The transformation process of the Sincor joint venture into the new mixed company Petrocedeño was not finalised by the end of 2007. StatoilHydro therefore held proved reserves at year end 2007 in the Sincor joint venture structure with a share of 15%. StatoilHydro's shareholding interest in Petrocedeño will be 9.677%. The change in StatoilHydro's share will result in a reduction of proved reserves corresponding to 68 million barrels following completion of the transformation process.

3.9.1 Report of DeGolyer and MacNaughton

DeGolyer and MacNaughton, independent petroleum engineering consultants, performs an independent evaluation of proved reserves, which was performed as of 31 December 2007 for our properties. DeGolyer and MacNaughton has delivered to us its summary letter report describing its procedures and conclusions, a copy of which follows below.

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

February 18, 2008

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, 2007, of certain properties in Algeria, Angola, Azerbaijan, Brazil, Canada, China, Iran, Ireland, Libya, Nigeria, Norway, Russia, the United Kingdom, the United States, and Venezuela owned by StatoilHydro ASA (StatoilHydro). The estimates are discussed in our "Report as of December 31, 2007 on Proved Reserves of Certain Properties owned by StatoilHydro ASA" (the Report). We also have reviewed StatoilHydro's estimates of reserves, as of December 31, 2007, 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, 2007, 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)	Net Equivalent (MMbbl)
2,389	20,319	6,010

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, 2007, 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)	Net Equivalent (MMbbl)
2,397	19,969	5,955

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 petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of November 29, 1996 (the "Petroleum Act"), and a number of 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.

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 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'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.
- 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 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 license. The Ministry of Petroleum and Energy holds executive discretionary power to award a production license and to determine the terms of that license. The Government is not entitled to award a license in an area until the Storting has decided to open the area in question for exploration.

A production license grants the holders 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 license. Notwithstanding the exclusive rights granted under a production license, the Ministry of Petroleum and Energy has the power to, in exceptional cases, permit third parties to carry out exploration in the area covered by a production license. For a list of our shares in production licenses, see report section Production - E&P Norway - Operational review.

Production licenses are normally awarded through licensing rounds. The first licensing round for NCS production licenses was announced in 1965. The award of the first licenses covered areas in the North Sea. Over the years the award of licenses 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 licenses in the Norwegian Sea. Beginning in 2003, the Norwegian government changed its policy on mature areas and introduced a scheme for award of production licenses named "Award in Predefined Areas" (APA) in mature parts of the Norwegian Continental Shelf. The award of licenses 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 license applications from individual companies and group applications, enabling us to choose our exploration and development partners.

Production licenses are awarded to joint ventures consisting of several companies. 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 license 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 license to license, but a decision is normally reached when a certain number of the members and a percentage of the ownership interests, specified individually in each license, have voted in favour of a proposal. The voting rules are structured so that a licensee holding more than 50% of a license normally cannot vote through a proposal on its own, but will need the support of one or more of the other licensees. In licenses 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 license as to the Norwegian State's exploitation policies or financial interests. This veto right has never been used.

Under the joint operating agreements covering licenses 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 licenses 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. The operator is in practice always a member of the joint venture holding the production license, 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 licenses 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 license. The work obligation will typically include seismic surveying and/or exploration drilling. If the licensees fulfil the obligations set out in the production license, they are entitled to require that the license be prolonged for a period specified at the time when the license is awarded, typically 30 years. The right to prolong the license does not apply as a main rule to the whole of the geographical area covered by the initial license, but only to a percentage, typically 50%. The size of the area which must be relinquished is determined at the time the license is awarded. In special cases, the Ministry of Petroleum and Energy may extend the duration of a production license.

If natural resources other than petroleum are discovered in the area covered by a production license, 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 license. 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 roughly a 5% reduction in output.

Licensees may buy or sell interests in production licenses 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 license, 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 licenses 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 licenses.

A license 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 licenses, the owners, which are in practice licensees under a production license, must prepare a plan for installation and operation. Licenses 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.

Licensees are required to prepare a decommissioning plan before a production license or a license 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 license 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 license 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.

Licenses 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 license period.

3.10.2 Gas sales and gas transportation

In contrast to the organization of gas sales prior to 1 June 2001, gas sales contracts with buyers for the supply of Norwegian gas are now concluded individually by each company.

The upstream gas transportation system consists of several pipelines owned by a joint venture called Gassled, see report section Norwegian gas transportation system.

The Norwegian authorities have by a royal decree of 20 December 2002 issued regulations 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. Further, 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 free capacity, in accordance with regulations, is allocated to users with a duly substantiated reasonable need for transportation of natural gas. Further, 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, consideration shall in case of spare capacity first be given to the owners' duly substantiated needs for capacity, which is limited to twice the owner's equity interest in the upstream pipeline network in question.

Based on authorization 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. 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 2008. 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

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 in this respect administered by the Ministry of Labour and Government Administration, all 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.

Licensees and other persons engaged in petroleum operations are required to maintain at all times a plan to deal with emergency situations. 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 licenses 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 losses or damages as a result of pollution caused by any of our NCS license 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. Set forth 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 2/3% 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 per cent 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, to a great extent, be offset. Group distributions are not deductible in our offshore income.

From 1 January 2004, dividends received have not been subject to tax in Norway. Exemptions exist for dividends from low-tax countries or portfolio investments outside the EEA.

From 26 March 2004, capital gains on realization of shares are not taxable and losses are not deductible. Exemptions exist for shares held in companies domiciled in low-tax countries or portfolio investments outside the EEA.

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 expenditures. 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 0.80 for 2007 and NOK 0.45 for 2008 per standard cubic meter of gas burned or directly released and per litre of oil burned. For 2008, companies operating on the NCS will 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 15.40 per kilogram of nitrogen oxide (NOK 15.39 for 2008).

Area fee. After the expiration of the initial exploration period, the holders of production licenses 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 licenses, the initial annual area fee is currently NOK 7,000 per square kilometre. The annual area fee is increased yearly by NOK 7,000 until it reaches NOK 70,000 per square kilometre.

Royalty. The obligation to pay royalty on the NCS was abolished at the end of 2005.

3.10.6 The Norwegian state as a regulatory authority

As a corporation based in Norway, we are subject to the laws and regulations of the Kingdom of Norway. Changes to relevant laws and regulations could have a significant impact on our operations. Various agencies and departments of the Kingdom of Norway exercise regulatory functions over our activities. The Ministry of Petroleum and Energy also exercises important regulatory powers over all petroleum operations of the companies of the NCS, including those of Statoil. For additional information about the Ministry of Petroleum and Energy's role, see previous report sections under Regulation for further details. A number of other agencies and departments, such as the Norwegian Petroleum Directorate, the Ministry of Finance, the Ministry of Labour and Government Administration, the Ministry of the Environment and the Norwegian Pollution Control Authority, exercise regulatory powers which affect important parts of our operations.

A significant part of the taxes we pay are paid to the Norwegian State, see previous report sections under Regulation for further details.

3.10.7 The Norwegian state's direct participation in petroleum operations on the NCS

The Norwegian State's policy as an owner 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 organized 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 licenses and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licenses 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 include:

- the partial privatization of StatoilHydro;
- 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, following the partial privatization;
- the transfer of responsibility over and management of the SDFI's assets from us to a new company which will be wholly owned by the Norwegian State; and

- the transfer of operational responsibility over certain pipelines on the NCS from us to a new company which, for the time being, is wholly owned by the Norwegian State.

3.10.8 Marketing and sale of the SDFI's oil and gas

Introduction. We have historically marketed and sold the Norwegian State's oil and gas as a part of our own production. 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 forth 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 license, 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 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 different 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.

3.10.9 Petoro AS - The SDFI management company

From the establishment of StatoilHydro in 1972 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 us. 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.

We were, until 17 June 2001, registered as licensee for all SDFI shares in licenses. In accordance with a decision made in an extraordinary general meeting on 10 May 2001, we were until this time also the manager of the SDFI shares in these licences on behalf of the Norwegian State. Where both the SDFI and we had an interest in the same licence, the department managing our interest also managed the SDFI interest. In fields with SDFI interests only, the interests were managed by a separate unit that we established for this purpose. Our tasks as the manager of the SDFI's interests have included attending management committee meetings for both the SDFI's and our own share in licences, and votes cast by us in management committee meetings have represented both the SDFI's and our own interests in the licences. We have also been responsible for marketing the petroleum of which the Norwegian State becomes the owner through the SDFI shares in production licences.

In connection with the restructuring, the Norwegian State on 9 May 2001 established a new State-owned company, Petoro AS, 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 Marketing and sale of the SDFI's 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.

3.10.10 Gassco AS - The gas transportation operating company

In connection with the restructuring of the Norwegian State's oil and gas interests, on 14 May 2001 the Norwegian State established a separate company, Gassco AS, which on 1 January 2002 took over as operator of the natural gas transportation system previously operated by us. 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 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 Norwegian gas transportation system and other facilities.

3.11 Competition

In the oil and gas industry there is intense competition for customers, production licenses, 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

Our principal offices located at Forusbeen 50, N-4035, Stavanger, Norway, comprise approximately 103,000 square meters of office space, and are owned by StatoilHydro.

We have interests in real estate in numerous countries throughout the world, but no one individual property is significant to us as a whole. We have no significant ongoing construction projects or plans to add new office space.

See Supplementary information on Oil and Gas producing activities in the F-pages for a description of our significant reserves and sources of oil and natural gas.

3.13 Related party transactions

Transactions with the Norwegian State

For a description of shares held by the Norwegian State, see report section Shareholder information-Major Shareholders, section 6.4. See also report section Financial performance-Liquidity and capital resources-Material contracts, section 4.2.3 for details on the merger between Statoil and Norsk Hydro's oil and gas activities.

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

As a result of the substantial percentage of industry in Norway controlled by the Norwegian State, there are many state-controlled entities with which we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State 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 53.9% 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 oil and natural gas liquids from the Norwegian State amounted to NOK 98,498 million (237 mmboe) and NOK 104,628 million (254 mmboe) in 2007 and 2006, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licences and sales on behalf of the Norwegian State) amounted to NOK 287 million and NOK 293 million in 2007 and 2006, respectively. 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 Regulation-Marketing and sale of the SDFI's oil and gas for more details.

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.

The three employee-elected members of the board of directors and two members of the executive Committee each entered into loan agreements under this facility prior to 30 July 2002, and had, as of 31 December 2007, an aggregate total balance outstanding payable to DnB NOR under this loan facility of NOK 149,076. Members of the executive committee and the board of directors may not enter into loans under the foregoing program.

4 Financial performance

The merger between Statoil and Hydro's oil and gas activities was a forceful response to increasing industry complexity and international competition. The merged StatoilHydro has an expanded technology base and stronger capabilities to execute larger and more demanding projects. The company has a broader global presence and a stronger portfolio of assets and resources. See previous sections for information about the nature and extent of our operations.

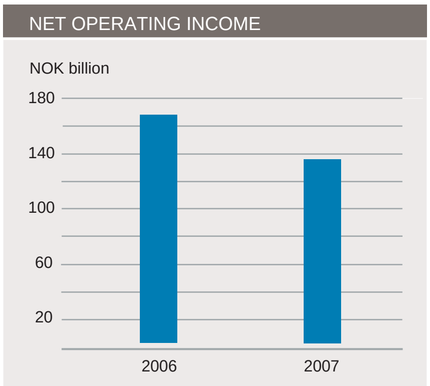
The successful execution and completion of the merger on 1 October 2007, was a key milestone in a year with a historic high activity level. The entitlement production of oil and gas increased by 3%, 15 new projects commenced production, an extensive exploration programme was executed, and the company gained access to new high quality projects and exploration acreage. StatoilHydro delivered a solid annual result and is well positioned for future growth and value creation.

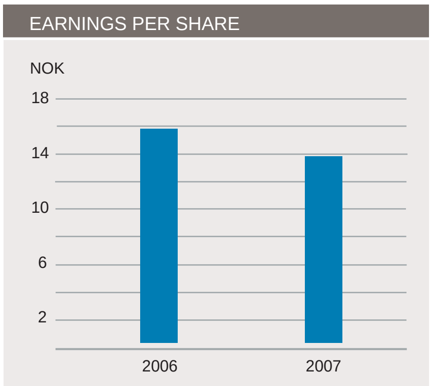
The following tables show selected consolidated financial and statistical data for StatoilHydro. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRSs) as adopted by the European Union (EU). The accounting policies applied by the Group also comply with IFRSs as issued by the International Accounting Standards Board (IASB).

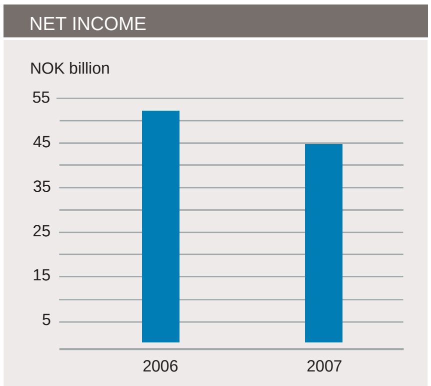
	For the year ended 31 December	
(in NOK million, except per share amounts)	**2007**	**2006**
Revenues	**521,665**	518,960
Net income (loss) from equity accounted investments	**609**	679
Other income	**523**	1,843
Total revenues and other income	**522,797**	521,482
Cost of Goods sold	**(260,396)**	(249,593)
Operating expenses	**(60,318)**	(44,801)
Selling, general and administrative expenses	**(14,174)**	(10,824)
Depreciation, amortisation and impairment	**(39,372)**	(39,450)
Exploration expenses	**(11,333)**	(10,650)
Total operating expenses	**(385,593)**	(355,318)
Net operating income	**137,204**	166,164
Interest income and other financial items	**2,305**	3,675
Interest and other finance expenses	**(2,741)**	(3,060)
Net foreign exchange gains (losses)	**10,043**	4,457
Net financial items	**9,607**	5,072
Income before tax	**146,811**	171,236
Income tax	**(102,170)**	(119,389)
Net income	**44,641**	51,847
Attributable to:		
Equity holders of the parent company	**44,096**	51,117
Minority interest	**(545)**	(730)
	44,641	51,847
Earnings per share for income attributable to equity holders of the company - basic and diluted	**13.80**	15.82
Dividend declared per ordinary share (1)	**9.12**	8.20
Weighted average number of ordinary shares outstanding	**3,195,866,843**	3,230,849,707

(1) Dividend declared per ordinary share in 2006 includes only dividend payment from former Statoil. In addition comes dividend payment of NOK 6.1 billion from Norsk Hydro ASA in 2007. See the Shareholder information section for a description of how dividends are determined and the share repurchase programme.

4.1 High activity level in new organisation





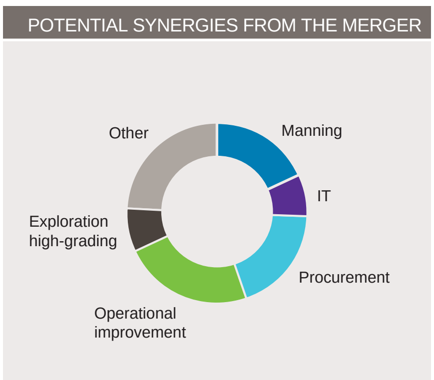


StatoilHydro delivered a total oil and gas entitlement production in 2007 of 1.724 mmboe per day. The contribution from international operations was record high and accounted for 18% of the entitlement production. Solid performance, combined with high oil and gas prices, was partly offset by an increase in operating costs and a decrease in production on the Norwegian continental shelf (NCS). The net operating income for 2007 of NOK 137 billion was also affected by restructuring costs related to the merger totalling NOK 11.1 billion.

The company reached major milestones in several projects on the NCS. During autumn 2007, the Ormen Lange project started production and export of gas to the UK, and was officially inaugurated in October. Also in October, the first LNG was shipped from the Snøhvit LNG plant on Melkøya. The LNG plant has suffered from operational challenges and there are still uncertainties related to the timing of regular and stable operations. In addition, eight projects on the NCS and five international projects came on stream in 2007. The company also sanctioned 13 new projects for development, of which four are outside Norway.

In 2007 StatoilHydro delivered an extensive exploration programme. Of a total of 71 exploration wells, 47 were drilled outside of the NCS. The company participated in 36 discoveries, of which 18 were made internationally. During 2007, the company added 215 million boe in proved reserves from new discoveries and extensions. 325 million boe were added from revisions and improved recovery. In total, the company achieved a reserve replacement ratio of 86% in 2007.

During 2007, StatoilHydro gained access to new growth opportunities. In June, the company acquired North American Oil Sands Corporation and established a position in Canadian oil sands. The position in the deepwater US Gulf of Mexico was strengthened by accessing new exploration licences in ordinary lease sales. Towards the end of the year, the company was selected as a partner in the development of the offshore gas and condensate field Shtokman. In 2008, the company has to date strengthened its international foothold by signing an agreement to acquire the remaining 50% share and operatorship of the Brazilian Peregrino field as well as an additional position, the Kaskida discovery, in the US Gulf of Mexico. The transaction is subject to government approval and the acquisition of the Kaskida discovery is also subject to other parties not exercising preferential rights to purchase. As of 4 April, the company has been formally notified that two of such parties intend to exercise their preferential rights.



As part of the merger process, the company executed a thorough evaluation of the organisation and operations. A potential of more than NOK 6 billion of annual synergies has been identified. These synergies confirm the significant value creation potential of the merger.

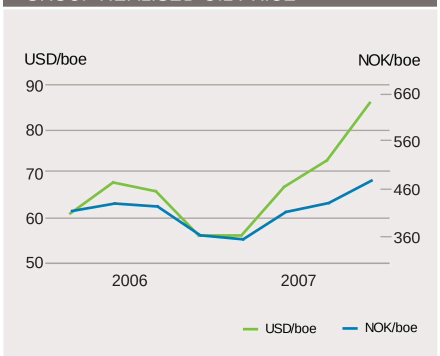
The report for 2007 is the first annual report in which financial statements for the merged StatoilHydro organisation are presented. Historical data have been restated as if the merged company had existed for all periods.

4.1.1 Group profit and loss analysis

(in NOK million)	For the year ended 31 December 2007	2006	Change
Total revenues and other income	**522,797**	521,482	0%
Operating expenses			
Cost of goods sold	**(260,396)**	(249,593)	4%
Operating expenses	**(60,318)**	(44,801)	35%
Selling, general and administrative expenses	**(14,174)**	(10,824)	31%
Depreciation, amortisation and impairment	**(39,372)**	(39,450)	(0%)
Exploration expenses	**(11,333)**	(10,650)	6%
Total operating expenses	**(385,593)**	(355,318)	9%
Net operating income	**137,204**	166,164	(17%)
Net financial items	**9,607**	5,072	89%
Income before tax	**146,811**	171,236	(14%)
Income tax	**(102,170)**	(119,389)	(14%)
Net income	**44,641**	51,847	(14%)

Operational data	For the year ended 31 December 2007	2006	Change
Average oil price (USD/bbl)	**70.5**	63.2	12%
USDNOK average daily exchange rate	**5.86**	6.42	(9%)
Average oil price (NOK/bbl)	**413**	406	2%
Gas prices (NOK/scm)	**1.69**	1.94	(13%)
Refining margin, FCC (USD/boe)	**8.4**	7.1	18%
Total entitlement oil prodction (1,000 boe/day)	**1,070**	1,057	1%
Total entitlement gas production (1,000 boe/day)	**654**	651	0%
Total entitlement oil and gas production (1,000 boe/day)	**1,724**	1,708	1%
Total oil liftings (1,000 boe/day)	**1,081**	1,048	3%
Total gas liftings (1,000 boe/day)	**654**	651	0%
Total oil and gas liftings (1,000 boe/day)	**1,735**	1,698	2%
Production cost (NOK/boe, last 12 months)	**44.1**	28.4	56%
Production cost normalised (NOK/boe, last 12 months)	**44.3**	28.1	58%

GROUP REALISED OIL PRICE



Revenues and other income totalled NOK 522.8 billion in 2007. This was NOK 1.3 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 Cost of goods sold and Sales, respectively.

From 2006 to 2007 realised oil prices measured in NOK increased by 2%. 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 off-set by a decrease in gas prices with a negative impact of NOK 10.4 billion.

DISTRIBUTION OF PROVED RESERVES

The volumes of oil lifted will 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 oil from the fields. **Total oil liftings** increased from 1.048 mmboe per day in 2006 to 1.081 mmboe per day in 2007.

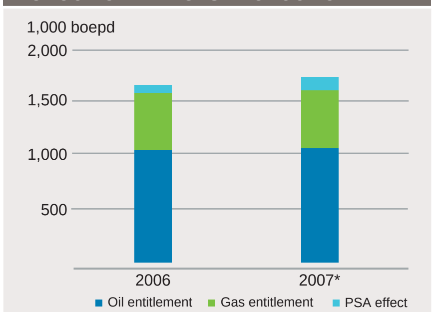
Entitlement volumes lifted is the basis for the revenue recognition while equity production volumes more directly affect operating costs. See report section Reported volumes for more details on the differences between equity and entitlement volumes. See below for more details on the difference between lifted and produced volumes.

Total natural gas sales were 42.0 bcm (1.48 tcf) in 2007 and 40.2 bcm (1.42 tcf) in 2006. The increase 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 0.6 billion in 2007 and NOK 0.7 billion in 2006.

Other income was NOK 0.5 billion in 2007 compared to NOK 1.8 billion in 2006. The income in 2007 was mainly related to gains from sale of assets whereas the income the previous year was mainly related to a change in the write-down of inventory to production cost and gains from sales of assets.

GROUP OIL AND GAS PRODUCTION



* At USD 60/boe the PSA effect is estimated to 107 mboe/d, i.e. entitlement production would be reported at 1,732 mboe/d

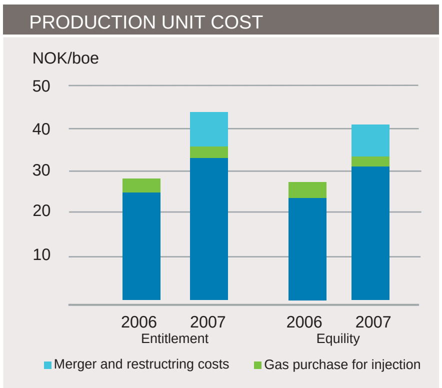
Cost of goods sold includes the cost of the oil and NGL production that we purchase from the Norwegian State pursuant to the Marketing Instruction. The cost of goods sold increased in 2007 to NOK 260.4 billion and was mainly due to higher oil prices measured in NOK.

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 60.3 billion in 2007 compared to NOK 44.8 billion in 2006. The increase 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 oil and gas production increased from 1,708 mmboe per day in 2006 to 1,724 mmboe per day in 2007. The increase in entitlement production was driven by a 31% increase internationally, which was partly offset by a minor decrease on the NCS. Equity production of oil and gas increased from 1,778 mmboe per day in 2006 to 1,839 mmboe per day in 2007.

Unit production cost measured in NOK was NOK 44.1 (USD 8.12) per boe in 2007 compared to NOK 28.4 (USD 5.23) per boe in 2006. The increase was mainly due to restructuring costs, start-up of new fields, increased maintenance costs and general industry cost pressure. Adjusted for restructuring costs and other costs arising from the merger, the average production cost per boe for 2007 was NOK 35.7. This amount includes NOK 2.5 related to the cost of purchased gas for reinjection in support of oil production. Divided by equity volumes, the production cost measured in NOK was 41.4 per boe in 2007, an increase of NOK 14.1 per boe compared to 2006.

Selling, general and administrative expenses include expenses related to the selling and marketing of our products such as business development costs, payroll and employee benefits and amounted to NOK 14.2 billion in 2007 compared to NOK 10.8 billion in 2006. The increase was mainly due to restructuring costs and other costs arising from the merger, partly offset by a pre-tax gain in 2006 of NOK 0.6 billion from the sale of Statoil Ireland.



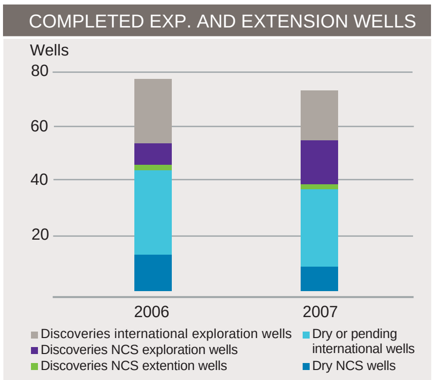
Depreciation, amortisation and impairment includes depreciation of production installations and transport systems, depletion of fields in production, amortisation of intangible assets and depreciation of capitalised exploration expenditure. It also includes write-downs of impaired long-lived assets. These expenses amounted to NOK 39.4 billion in 2007, compared to NOK 39.5 billion in 2006.

A decrease of NOK 3.3 billion in depreciation, amortisation and impairment expenses in 2007 compared to 2006 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 the 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 2007 and write-offs of exploration expenditure capitalised in previous years. The exploration expense was NOK 11.3 billion in 2007 and NOK 10.7 billion in 2006.

	For the year ended 31 December		
Exploration (in NOK million)	**2007**	**2006**	**Change**
Exploration expenditure (activity)	**14,241**	13,391	6%
Expensed, previously capitalised exploration expenditure	**1,660**	1,447	15%
Capitalised share of current period's exploration activity	**(4,569)**	(4,188)	(9%)
Exploration expenses	**11,333**	10,650	6%

The increase of 6% in the exploration expense was mainly due to higher exploration activity, generally more expensive wells and an increase in the expensing of previously capitalised licences and well expenditure.



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 137.2 billion in 2007, compared to NOK 166.2 billion in 2006. The decrease was mainly due to an increase in operating, selling and administrative expenses stemming in part from restructuring and other costs arising from the merger of NOK 11.1 billion, negative change in derivatives of NOK 10.0 billion, new fields coming on stream and increased activity levels. The restructuring costs and other costs arising from the merger have been recorded primarily under operating and general and administrative expenses, and have been allocated to the business areas where possible.

Restructuring costs and other costs arising from the merger primarily relate to pensions and early retirement costs and impairment of assets in Sweden.

In 2007 we reported a **Net financial items** income of NOK 9.6 billion, compared to a net financial items income of NOK 5.1 billion in 2006. The changes from year to year were 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 with 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 interests 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 held by our insurance captive, Statoil Forsikring AS, and commercial papers held by Statholding AS, resulted in a loss of NOK 0.2 billion in 2007, compared to a loss of NOK 0.6 billion in 2006.

The Norwegian central bank's closing rate for USDNOK was 5.41 on 31 December 2007 and 6.26 on 31 December 2006. These exchange rates have been applied in StatoilHydro's financial statements.

The effective **Income tax** rates were 69.6% and 69.7% in 2007 and 2006, respectively.

Adjusted for the non-recurring NOK 2.0 billion reduction of deferred tax liabilities relating to new tax rules for allocation of financial items with respect to the NCS and temporary differences in intercompany transactions, the tax rate in 2006 was 70.9%. 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.

The effective tax rate is calculated as income taxes divided by income before income taxes and minority interest. 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.

In 2007, the **Minority interest** in net profit was NOK 0.6 billion, compared to NOK 0.7 billion in 2006. The minority interest is primarily related to the Mongstad crude oil refinery.

Net income was NOK 44.6 billion in 2007, compared with NOK 51.9 billion in 2006. The decrease was mainly due to a lower operating income primarily due to 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 4.20 per share for 2007 to the Annual General Meeting, as well as NOK 4.30 per share in special dividend, making an aggregate total of NOK 27,085 million.

4.1.2 Group outlook

We expect to continue our high level of exploration activity in 2008 and we plan to drill approximately 70 exploration wells. On the NCS, a significant part of the drilling activity is expected to be in mature areas close to existing infrastructure. We also plan to drill several wells in frontier areas of the Norwegian Sea and in the Barents Sea. Internationally we plan to continue to pursue a high level of exploration activity combined with targeted business development consistent with our strategy to further grow our resource base. Rig capacity has been secured for the number of wells in the 2008 drilling programme, and we believe we are well positioned for further exploration drilling beyond 2008 based on our current drilling programme and rig commitments.

Our entitlement production estimate for 2008 is approximately 1.75 mmboe per day (at USD 75 per barrel).

2007 was one of the most volatile periods in the product, gas liquid and crude oil markets. High prices were experienced during the year and we believe that prices will remain relatively high and volatile at least in the near term.

Changes in supply, demand and cost of alternative fuels will be reflected in the price formation of natural gas. Higher development costs in the industry combined with the fact that the transportation distances between new supply regions and markets are increasing therefore suggest that gas prices may increase over time to ensure development of sufficient supplies. However, a number of other factors may still cause lower prices. For instance, prices in the shorter term gas market may be adversely affected by seasonal demand variations at the same time as new capacity and new fields are coming on stream towards 2010. The value of natural gas will also be influenced by the price development and regulation in the power segment where gas is competing with coal, renewable- and nuclear energy. We have also seen that gas markets are moving from being pure regional markets to being more influenced by global supply and demand balances. LNG in the Atlantic basin, for instance, is responding to changes in prices between major markets in Europe, the US and Asia, taking advantage of arbitrage opportunities, creating higher volatility. Our views on these events make us in sum believe that we have increased value creation potential by combining the proximity of our infrastructure to favourable markets with advanced marketing competence and skills.

In 2008, we estimate organic capital expenditures for the group of approximately NOK 75 billion and approximately NOK 80 billion in 2009, assuming an exchange rate of USDNOK 6.0.

Unit production cost for equity volumes is estimated in the range of NOK 33 to 36 per barrel in the period from 2008 to 2012, excluding purchases of fuel and gas for injection.

It is our ambition to deliver a competitive ROACE compared with our peers.

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.

4.1.3 Segment performance and analysis

The following table details certain financial information for our four business segments. When combining business segment results, we eliminate intercompany sales. These include transactions recorded in connection with our oil and natural gas production in the Exploration & Production Norway (EPN) or International Exploration & Production (INT) segments and also in connection with the sale, transport or refining of our oil and natural gas production in the Manufacturing & Marketing (M&M) or Natural Gas (NG) segment. EPN produces oil, which it sells internally to Oil Sales, Trading and Supply 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 business area, 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 the NG segment. Management has recently decided to update the transfer price formula for natural gas produced by EPN and marketed and sold by NG to better reflect fundamental changes since the previous formula was set in 2002 in the markets for competing energies, i.e. crude oil, for developments in natural gas markets and for changes in the natural gas sales contracts portfolio. The change will be effective from 1 January 2008 and will be reflected in our financial reporting going forward, without restating prior periods.

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. The transfer price of sales of natural gas from EPN to NG is NOK 0.32 per standard cubic metre, adjusted quarterly by the average USD oil price over the previous six months in proportion to USD 15 per barrel. The average transfer price for natural gas per standard cubic metre was NOK 1.39 in 2007 and NOK 1.35 in 2006.

The table shows certain financial information for our four segments, including intercompany eliminations for each of the years in the two-year period ending 31 December 2007.

(in NOK million, except per share amounts)	For the year ended 31 December 2007	2006
Exploration & Production Norway		
Total revenues	**179,244**	179,199
Net operating income	**123,150**	135,140
Non-current assets	**153,559**	152,328
International Exploration & Production		
Total revenues	**41,601**	32,602
Net operating income	**12,161**	3,917
Non-current assets	**109,731**	98,553
Natural Gas		
Total revenues	**73,434**	97,069
Net operating income	**1,562**	21,693
Non-current assets	**40,271**	35,167
Manufacturing & Marketing		
Total revenues	**428,043**	411,990
Net operating income	**3,776**	7,280
Non-current assets	**28,891**	26,735
Other and eliminations		
Total revenues	**(199,525)**	(199,378)
Net operating income	**(3,445)**	(1,866)
Non-current assets	**20,976**	19,865
StatoilHydro group		
Total revenues	**522,797**	521,482
Net operating income	**137,204**	166,164
Non-current assets	**353,428**	332,648

4.1.4 Exploration and Production Norway

Kristin. High pressure and high temperature

Ormen Lange. Flow assurance and deep water

Tordis. Sub-sea processing

Discovering new resources is a top priority. In 2007, we completed 24 exploration wells, of which 16 were discoveries. In addition, we completed two exploration extensions, of which both resulted in discoveries. Total exploration expenses were NOK 3.6 billion in 2007, compared with NOK 3.5 billion in 2006.

Six exploration wells have been completed so far in 2008. Four of these are discoveries: Gamma, Marulk, M-structure and Obesum. In addition one exploration extension is completed, Fram C-Øst, which was a discovery.

We are focused on increased oil and gas recovery, and we invest in order to increase recovery rates for our fields. The continued drilling of new production wells is of major importance in countering the natural decline in production from mature fields on the NCS. In 2007, we drilled 66 new production wells and we plan to drill approximately 80 wells in 2008.

Our production of oil and gas on the NCS averaged 1.417 mmboe per day in 2007, compared to 1.474 mmboe per day in 2006. Our total production was negatively affected by incidents that caused interruptions to production on the NCS and lower gas off-take in Europe than expected, which was partly offset by new projects coming on stream.

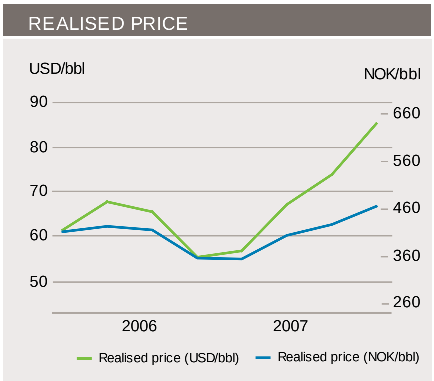
In total, eight projects came on stream on the NCS in 2007, four on new fields and four reconfiguration/increased oil recovery projects. These projects make a substantial contribution to our production and transport capacity. Both Ormen Lange and Snøhvit came on stream in October and production also commenced from the Statfjord Late Life project, Tordis subsea processing, Skinfaks/Rimfaks IOR, Huldra Tail-end and Njord gas export. In addition, nine new projects were sanctioned in 2007. Volve started producing in February 2008.

The total capital expenditure of NOK 31.1 billion in 2007 was higher than in previous years, as a result of many projects under development.

Restructuring costs and other costs relating to the merger amounting to NOK 5.5 billion were charged to income in 2007.

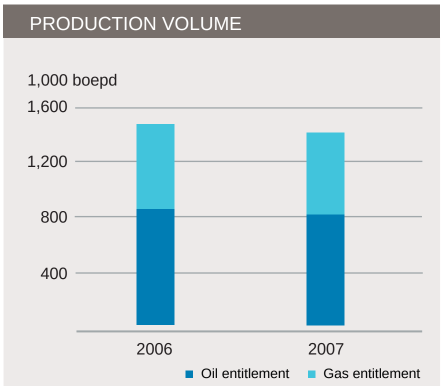
4.1.4.1 Profit and loss analysis

(in NOK million)	For the year ended 31 December 2007	2006	Change
Total revenues and other income	**179,244**	179,199	0%
Operating, general and administrative expenses	**29,426**	19,641	50%
Depreciation, amortisation and impairment	**23,030**	20,938	10%
Exploration expenses	**3,638**	3,480	5%
Total expenses	**56,094**	44,059	27%
Net operating income	**123,150**	135,140	(9%)
Operational data			
Oil price (USD/bbl)	**70.9**	63.6	11%
Production cost per boe	**43.3**	27.0	60%
Liftings			
Oil (1,000 bbl/day)	**831**	856	(3%)
Natural gas (1,000 boe/day)	**599**	610	(2%)
Total oil and natural gas liftings (1,000 boe/day)	**1,430**	1,467	(3%)
Production			
Entitlement oil (1,000 bbl/day)	**818**	864	(5%)
Entitlement natural gas (1,000 boe/day)	**599**	610	(2%)
Total entitlement oil and natural gas production (1,000 boe/day)	**1,417**	1,474	(4%)



We generated **total revenues** of NOK 179.2 billion both in 2007 and 2006. 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 USDNOK 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.

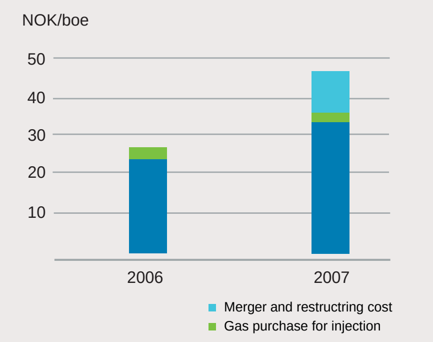
The average daily lifting of oil in 2007 was 831 mbbl per day, compared to 856 mbbl per day in 2006.



Average daily entitlement oil production in 2007 was 818 mbbl per day, compared to 864 mbbl per day in 2006. The reduced production was largely caused by the shut down of production on the Kvitebjørn field from 1 May 2007 in order to enable safe drilling operations, as well as to a natural decline on the Oseberg field. Kvitebjørn started up again on 16 January 2008, and it is currently producing at full capacity, although it is expected to be shut down again for approximately three months from late June 2008 to allow for repair work on the damaged gas export pipeline. The reduction in production was partly offset by increased production from the Kristin field, which has now reached plateau level.

The average daily entitlement gas production was 599 mboe in 2007 (equal to 95.2 mmcm or 3.36 mmcf), compared to 610 mboe in 2006 (equal to 97.0 mmcm or 3.42 mmcf).

UNIT PRODUCTION COST



The unit production cost was USD 8.09 per boe in 2007 and USD 4.21 per boe in 2006. The unit of production cost measured in NOK was NOK 46.26 per boe in 2007 and NOK 26.93 per boe in 2006. The production cost mainly consists of operating plant costs.

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. Operating plant costs increased by NOK 3.2 billion, due to both higher activity and increased pressure on costs in the industry.

Operating, general and administrative expenses were NOK 29.4 billion in 2007 and NOK 19.6 billion in 2006. Operating costs amounted to NOK 29.1 billion in 2007 and NOK 19.2 billion in 2006. The general and administrative cost elements in 2007 and 2006 largely consisted of research and development costs.

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.

Depreciation, depletion and amortisation expenses were NOK 23.0 billion in 2007 and NOK 20.9 billion in 2006. 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 2007 amounted to NOK 5.7 billion, compared to NOK 4.6 billion in 2006. 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. 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 2007 were NOK 3.6 billion, compared to NOK 3.5 billion in 2006.

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.

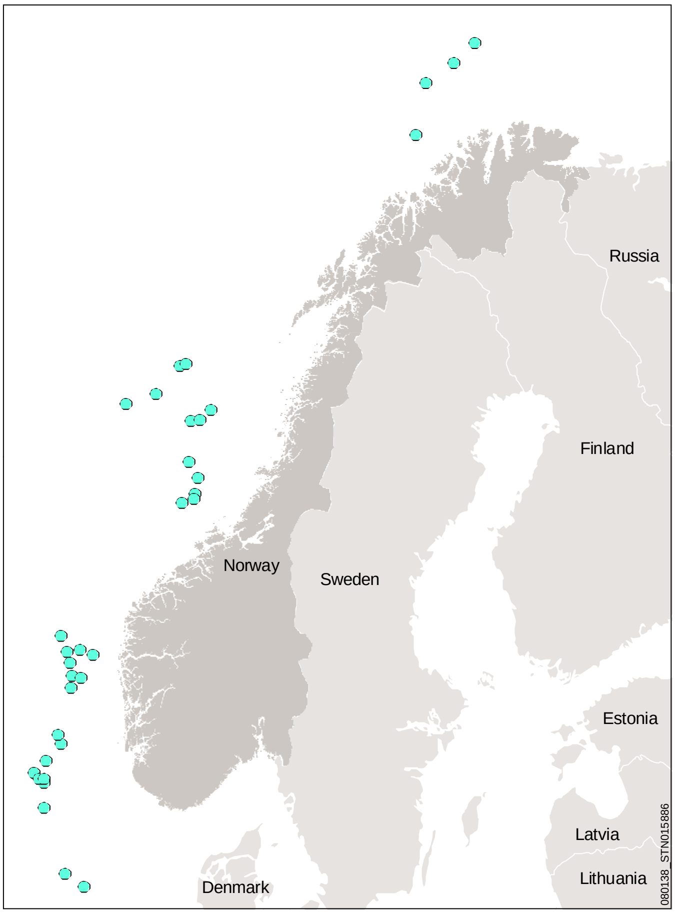
Drilling of five exploration and two exploration extension wells was ongoing at year end 2007.

The reconciliation of exploration expenditure with exploration expenses is shown in the table below.

Exploration (in NOK million)	**2007**	**2006**
Exploration expenditure (activity)	**5,749**	4,649
Expensed, previously capitalized exploration expenditure	**50**	177
Capitalized share of current period's exploration activity	**(2,161)**	(1,346)
Exploration expenses	**3,638**	3,480

Net operating income in 2007 was NOK 123.2 billion, compared to NOK 135.1 billion in 2006. The NOK 11.9 billion decrease in 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 exploration activity in 2008 and we plan to drill approximately 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 several wells in frontier areas of the Norwegian Sea and in the Barents Sea. We have secured rig capacity for our drilling activity level in 2008.

Measures have been initiated to further improve both regularity on our installations and our drilling efficiency. The full effect of these improvement programmes is not expected to be realised in 2008, but will be essential if we are to reach our production ambition in 2012.

There are uncertainties regarding production on Snøhvit. The LNG plant has suffered from operational challenges and there are still uncertainties related to the timing of regular and stable operations. Gas exports from Kvitebjørn and Visund will be halted during the repair of the Kvitebjørn gas pipeline in mid-2008.

4.1.5 International Exploration and Production

StatoilHydro drilled 150 exploration wells last winter in Canada oil sands using this type of onshore drilling rig.

Helge Lund, CEO of StatoilHydro and Alexei Miller, CEO of Gazprom sign the Shtokman agreement on 25 October 2007.

US Gulf of Mexico. At the yard in Corpus Christie, work is underway to complete the Tahiti platform.

The strategy of International Exploration & Production (INT) is to access new resources through world-class exploration and focused business development and to move resources effectively into production through our proven project execution and operational experience from the NCS.

International exploration activities were at a record level in 2007. During the year, we drilled 58 wells, 47 of which were completed. Eighteen wells have been announced as discoveries at year end. Several wells are still under evaluation. The total exploration expenses were NOK 7.7 billion in 2007, compared with NOK 7.2 billion in 2006.

Acquisitions in 2007 included the purchase of 100% of the shares in North American Oil Sands Corporation and the acquisition of the UK heavy oil fields Mariner, Mariner East and Bressay. Our interests in these fields are 44.44%, 62% and 81.63%, respectively. In addition, a separate agreement has been concluded with the Canadian companies Silverstone and Wilderness for an acquisition of 30% interest in the Broch discovery in block 9/16.

We signed a framework agreement with Gazprom to become a partner in the Shtokman development phase 1, giving us a 24% equity interest in Shtokman Development Company. In 2007, we divested ourselves of small mature producing assets in the shelf of the US Gulf of Mexico and in the UK.

In 2007, our international entitlement production increased significantly to 307 mboe per day from 234 mboe per day in 2006. The average daily equity production of oil and gas was 422 mboe per day in 2007, compared to 304 mboe in 2006. The difference between entitlement and equity volumes is the result of deductions for among other things, royalty and the host government's share of profit oil under the terms of most PSA regimes.

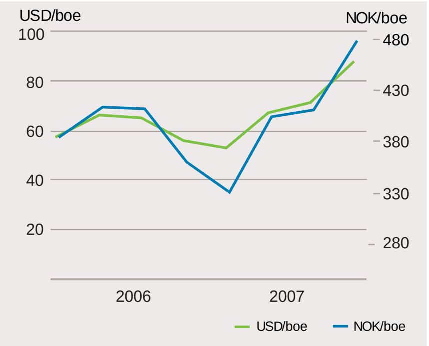
The total capital expenditure of NOK 36.2 billion in 2007 was higher than in previous years, triggered by many projects under development in addition to the acquisition of new assets to secure longer term growth, such as NAOSC in Canada and the UK heavy oil fields.

Restructuring costs and other costs relating to the merger totalling NOK 1.3 billion were charged to income in 2007.

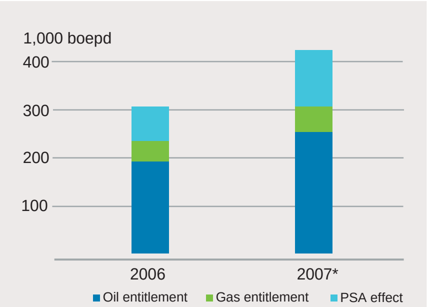
4.1.5.1 Profit and loss analysis

(in NOK million)	For the year ended 31 December 2007	2006	Change
Total revenues and other income	**41,601**	32,602	28%
Operating, general and administrative expenses	**10,642**	7,145	49%
Depreciation, amortisation and impairment	**11,103**	14,370	(23%)
Exploration expenses	**7,695**	7,170	7%
Total expenses	**29,440**	28,685	3%
Net operating income	**12,161**	3,917	210%
Operational data			
Oil price (USD/bbl)	**69.1**	60.9	13%
Production cost per barrel- entitlement (USD)	**5.87**	5.84	1%
Liftings			
Oil (1,000 bbl/day)	**250**	191	31%
Natural gas (1,000 boe/day)	**55**	40	37%
Total oil and natural gas liftings (1,000 boe/day)	**305**	232	32%
Production			
Entitlement oil (1,000 bbl/day)	**252**	194	30%
Entitlement natural gas (1,000 boe/day)	**55**	40	37%
Total entitlement oil and natural gas production (1,000 boe/day)	**307**	234	31%

REALIZED OIL AND GAS PRICE



PRODUCTION



* At USD 60/boe the PSA effect is estimated to 107 mboe/d, i.e. entitlement production would be reported at 315 mboe/d

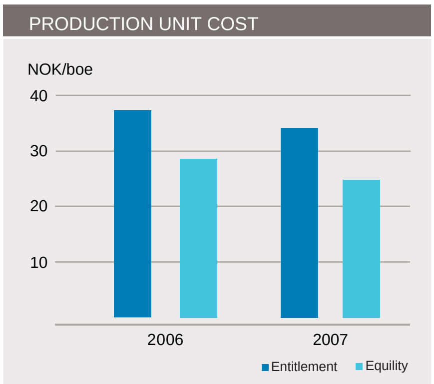
We generated **total revenues** of NOK 41.6 billion in 2007, compared to NOK 32.6 billion in 2006. The increase was mainly related to a 32% increase in lifted volumes, which contributed NOK 9.8 billion, and a 4% increase in realised oil prices in NOK, which contributed NOK 1.3 billion, partly offset by a 29% decrease in the realised gas price measured in NOK, which contributed negatively in the amount of NOK 1.5 billion.

The average daily oil lifting was 250 mbbl in 2007, compared with 191 mbbl in 2006.

The average daily entitlement production of oil was 252 mbbl in 2007, compared with 194 mbbl in 2006. The 30% increase in average daily oil production from 2006 to 2007 was mainly related to the ramp up of production from Dalia, the West and East Azeri part of the ACG field and In Amenas, which started production in the fourth quarter of 2006, the start-up of new fields, such as Rosa and Marimba, which came on stream in the second and third quarters of 2007, respectively, as well as increased production from Terra Nova, which was shut down for most of 2006. This was partly offset by lower entitlement production under the PSAs in Angola.

The average daily entitlement production of gas was 55 mboe in 2007 (equivalent to 9.35 mmcm or 330 mmcf), compared to 40 mboe in 2006 (equivalent to 6.80 mmcm or 240 mmcf). The 37% increase in daily gas production was mainly related to the start-up of new fields, such as Shah Deniz in the first quarter 2007 and the Eastern Gulf fields in the US GoM (Q, San Jacinto and Spiderman) in the third and fourth quarter 2007.

The average daily equity oil and gas production was 422 mboe per day in 2007, compared with 304 mboe in 2006.



The unit of production cost based on entitlement volumes was USD 5.87 per boe in 2007 and USD 5.84 per boe in 2006. Measured in NOK, it was 34.41 per boe in 2007 and 37.50 per boe in 2006. The 8% decrease in unit of production cost measured in NOK from 2006 to 2007 was mainly due to a decrease in the USDNOK exchange rate.

The unit of production cost based on equity volumes was USD 4.27 per boe in 2007 and USD 4.50 per boe in 2006. Measured in NOK it was 25.04 per boe in 2007 and 28.87 per boe in 2006. See report section Reported Volumes for a description of entitlement and equity volumes.

Operating, general and administrative expenses. Due to increased royalty and extraction tax in Venezuela and Canada, increased transport costs, new fields in production, increased costs related to the acquisition of NAOSC, pension and general operating costs, total operating, general and administrative expenses increased by NOK 3.5 billion from 2006 to 2007, of which restructuring costs and other costs arising from the merger amounted to NOK 1.3 billion.

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.

Exploration expenditure was NOK 8.5 billion in 2007, compared with NOK 9.5 billion in 2006. The decrease was mainly due to higher drilling activity in 2006.

Exploration expenses were NOK 7.7 billion in 2007, compared with NOK 7.2 billion in 2006. Increased exploration expenses were mainly related to higher expensing of exploration costs capitalised in previous years, partly offset by a decrease in exploration expenditure related to slightly lower drilling activity in 2007 than in 2006.

In total, 47 exploration and appraisal wells were completed in 2007 and, at year end, 18 were considered to be discoveries or confirmed discoveries. At year end, fourteen wells were pending final evaluation. In 2006, 55 exploration and appraisal wells were completed, 24 of which were considered discoveries.

Net operating income in 2007 was NOK 12.2 billion compared to NOK 3.9 billion in 2006. In addition to the price and volume effects, the increase was mainly related to a NOK 3.3 billion decrease in depreciation, amortisation and impairment expenses, which was offset by a NOK 3.5 billion increase in operating, general and administrative expenses of which restructuring and other costs arising from the merger amounted to NOK 1.3 billion, and a NOK 0.5 billion increase in exploration expenses.

4.1.5.2 Outlook

Seventy-five per cent of the new fields contributing to our 2012 production are sanctioned. The Mondo field came on stream in January 2008. Other fields planned for start-up in 2008 include Saxi Batuque and Gimboa in Angola, Agbami in Nigeria and ACG phase III in Azerbaijan.

We plan to continue to pursue high exploration activity combined with targeted business development consistent with our strategy in order to further expand our resource base. We expect to continue to develop resources effectively into production through our proven project execution and operational experience from the NCS.

Approximately 35 exploration and appraisal wells are expected to be drilled in 2008.

Rig capacity has been secured for our drilling activity level in 2008, and we believe we are well positioned for exploration drilling beyond 2008 based on our current drilling programme and rig commitments.

4.1.6 Natural Gas

Ormen Lange on stream. Gas from the Ormen Lange field is transported through the Langeled pipeline system to Easington in the UK

Arctic Discoverer docked at Cove Point. The first cargo of gas from the Norwegian continental shelf arrived in the USA on 21 February 2008. This shipment of Snøhvit LNG is the first delivery of gas from Europe to the world's largest energy market.

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 again at a high level in 2007 and the level of NCS gas exports is expected to grow. In 2007, StatoilHydro sold 35.6 bcm entitlement gas. In addition we sold 31.2 bcm NCS gas on behalf of the SDFI. Most of the gas was sold to Continental energy providers under long-term contracts. Our market share in 2007 was approximately 20-25% in Germany and France and approximately 15% in the UK.

In 2007, the first gas was delivered from the Shah Deniz field in Azerbaijan to Turkey, where the bulk of the gas is sold. At plateau level, Shah Deniz stage 1 is expected to produce around 8.6 bcm gas annually. A potential stage 2 of the Shah Deniz field is under development.

Important strategic milestones for us in 2007 included the opening of the Tampen Link pipeline, the start-up of the Ormen Lange field and the first LNG shipment from Snøhvit.

Two significant factors strongly influenced our financial results: the external sales price and the internal transfer price. In 2007, natural gas prices fell compared with the high level in 2006. Our average natural gas price for European piped gas was NOK1.69/cubic metre in 2007.

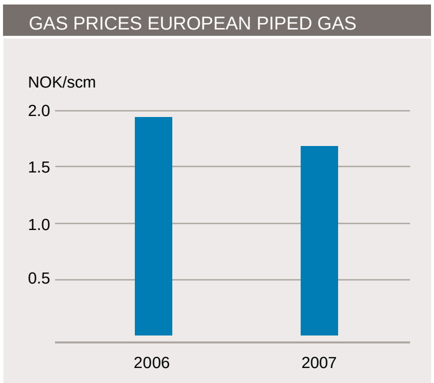
All of the gas from the NCS sold by the Natural Gas business area is purchased from Exploration & Production Norway. The internal transfer price formula is linked to the oil price for Brent Blend. High oil prices throughout 2007 have led to relatively high internal gas prices. In combination with the relatively low external sales prices for gas, our margins decreased significantly in 2007. In addition, losses on the fair value of derivatives also affected our results in 2007.

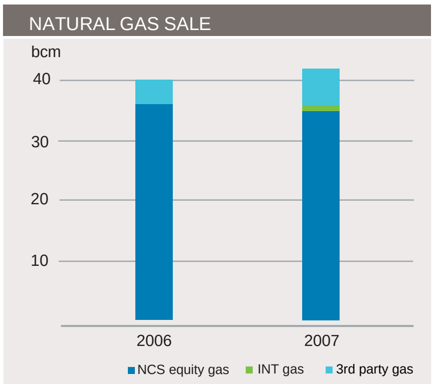
The total capital expenditure of NOK 2.1 billion in 2007 was lower than in previous years, due to fewer projects being under development. In addition, three LNG vessels and associated LNG companies were transferred from Exploration & Production Norway to Natural Gas in 2007, amounting to NOK 2.4 billion.

Restructuring costs and other costs relating to the merger totalling NOK 1.3 billion were charged to income in 2007.

4.1.6.1 Profit and loss analysis

(in NOK million)	For the year ended 31 December 2007	2006	Change
Total revenues and other income	**73,434**	97,069	(24%)
Cost of goods sold	**56,650**	61,342	(8%)
Operating, selling and administrative expenses	**13,377**	12,609	6%
Depreciation, amortisation and impairment	**1,845**	1,425	29%
Total expenses	**71,872**	75,376	(5%)
Net operating income	**1,562**	21,693	(93%)
Operational data			
Natural gas sales (StatoilHydro entitlement) (bcm)	**35.6**	35.9	(1%)
Natural gas sales (third-party volumes) (bcm)	**6.4**	4.3	49%
Natural gas sales (bcm)	**42.0**	40.2	4%
Natural gas price (NOK/scm)	**1.69**	1.94	(13%)
Transfer price natural gas (NOK/scm)	**1.39**	1.35	2%
Regularity at delivery point	**100%**	100%	0%





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 73.4 billion in 2007, compared with NOK 97.1 billion in 2006. The 24% decrease from 2006 to 2007 was mainly due to declining natural gas prices measured in NOK in 2007 and negative changes in the fair value of derivatives.

The total natural gas sales were 42.0 bcm (1.48 tcf) in 2007 and 40.2 bcm (1.42 tcf) in 2006. 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 mainly relates to production problems on Kvitebjørn throughout 2007, and it was partly offset by the start-up of Ormen Lange in October 2007.

Of the total natural gas sales in 2007, we sold 35.6 bcm (1.26 tcf) of entitlement gas, which included 0.8 bcm (0.03 tcf) of gas from Shah Deniz in Azerbaijan. The average gas price for our European gas sales was NOK 1.69 per scm in 2007, compared to NOK 1.94 per scm in 2006, a decrease of 13%. The decrease in price from 2006 to 2007 was mainly due to a decrease in prices for oil products (such as gas oil and fuel oil) and other competing energy sources, as well as lower 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.

Cost of goods sold decreased by 8% from 2006 to 2007, from NOK 61.3 billion to NOK 56.7 billion. The decrease in cost of goods sold mainly relates to a decrease in the third party purchase price of natural gas. This was partly offset by a slight increase in the transfer price paid to E&P Norway and an increase in third party purchase volumes from 2006 to 2007.

Operating, selling and administrative expenses increased by 6% from 2006 to 2007. This was mainly related to early retirement cost accruals and increased accruals for removal costs.

Net operating income for 2007 was NOK 1.6 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.

4.1.6.2 Outlook

We believe there is sufficient supply in Europe, Asia and North America to meet demand expectations in the short term. In the longer term, however, the market balance is more uncertain and will depend on a number of factors, such as how demand responds to gas and energy prices, the development of LNG projects and potential new Russian supplies coming on stream.

We believe that the future gas prices will provide efficient signals both to users of gas and owners of potential gas projects. Higher costs in the industry also suggest that sales prices may increase over time, thus ensuring sufficient supplies.

The short term gas market is affected by new capacity and new fields coming on stream. We have also seen that LNG in the Atlantic basin is responding to changes in prices between major markets, taking advantage of arbitrage opportunities. The UK gas market has become more liquid and is able to absorb volumes from Ormen Lange without severe impacts on prices. Our view on these events is that we have value creation potential through increased gas exports due to the proximity of our infrastructure to favourable markets.

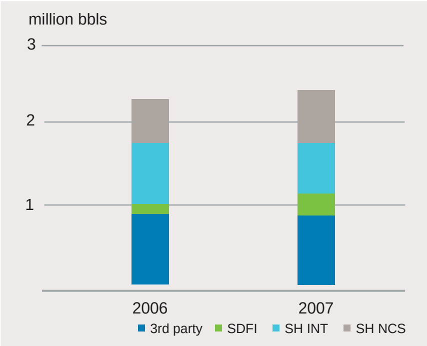
In the long term, we continue to have a positive view of gas as an energy source for Europe. Indigenous production of gas in the EU is expected to decline, while demand for gas is expected to increase, particularly due to the lower carbon footprint of natural gas compared with oil and coal. The trend for LNG as a link between continental markets is expected to continue as more LNG will come on stream, making gas a commodity that is priced more on a global basis in the long term.

In 2008, we plan to continue to seek added value through balancing, trading and optimisation, maximising the value of our gas sales portfolio and developing the next generation gas business. Key activities are expected to include planning with a view to utilising the expansion capacity at Cove Point, further preparation for a Shah Deniz stage 2 and focusing on maintaining a low cost level. Mitigation activities to meet our contractual obligations continue in 2008.

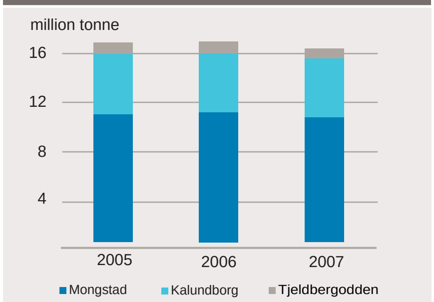
The upgrading of the Kårstø gas plant and the expected start-up of the Aldbrough storage facility are both projects of great importance to us in 2008. Aldbrough is expected to start commercial operations in late 2008. The storage facility will provide us with a new tool for trading and optimisation activities.

4.1.7 Manufacturing and Marketing

TRADED VOLUMES PER DAY OF OIL

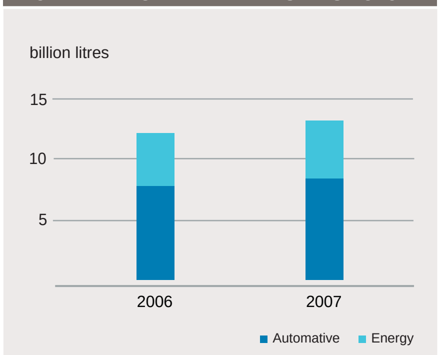


ACTUAL THROUGHPUT*



* Actual throughput of crude oils, condensates, feed and blendstock (excl. crude export)

TOTAL ENERGY AND RETAIL SALES VOLUME



In 2007, we continued to focus on streamlining the portfolio through investments and divestments, standardisation and simplification throughout the business area in order to create more value as well as an efficient and value chain-focused organisation.

The total capital expenditure of NOK 4.8 billion in 2007 was higher than in previous years, triggered by high activity in projects and modifications at our refineries.

Restructuring costs and other costs relating to the merger totalling NOK 1.2 billion were charged to income in 2007.

Oil sales, trading and supply

With average crude and condensate sales of 2.1 mmbbl per day in 2007, we still rank as one of the world's largest net sellers of crude. Of our daily sales of 2.1 mmbbl, approximately 1.0 mmbbl were our own equity volumes, 0.5 mmbbl were third party volumes and 0.6 mmbbl were SDFI volumes. Including NGL, the average sales volume was 2.4 mmbbl per day in 2007 compared with 2.3 mmbbl per day in 2006.

Even though the NCS production of crude oil is decreasing, we are still continuing to strengthen our global trading positions and have increased our flexibility by trading in third party volumes. The average daily third party crude volume sold in 2007 of 524 mbbl was an increase of approximately 25% from 2006.

Manufacturing

Mongstad continued to have good regularity (97.8%) in 2007, but Tjeldbergodden had a planned but extended turnaround and a 30-day shutdown due to an interruption in gas deliveries during July and August. Kalundborg also had a planned but extended turnaround in parts of the refinery that lasted for 62 days. The Kalundborg plant came on stream again in June.

Energy and retail

We have maintained our leading energy and retail positions, and have the leading or second largest share in most of the markets in which we operate.

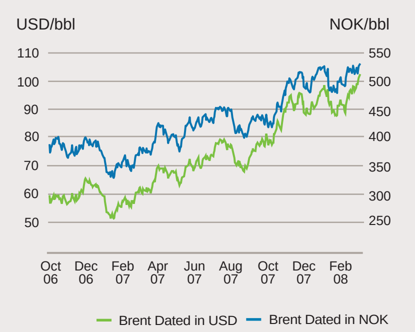
In 2007, we sold our energy and retail business on the Faeroe Islands and entered into a purchase agreement with ConocoPhillips for the Scandinavian JET retail network of 271 unmanned service stations. The purchase is subject to approval by the EU Commission.

We also strengthened our position as the leading supplier of bio fuels in 2007. Bio fuels are now available at more than 1,300 service stations in seven different countries.

4.1.7.1 Profit and loss analysis

(in NOK million)	For the year ended 31 December 2007	2006	Change
Total revenues and other income	**428,043**	411,990	4%
Cost of goods sold	**401,804**	383,362	5%
Operating, selling and administrative expenses	**19,630**	19,068	3%
Depreciation, amortisation and impairment	**2,833**	2,280	24%
Total expenses	**424,267**	404,710	5%
Net operating income	**3,776**	7,280	(48%)
Operational data			
FCC margin (USD/bbl)	**8.4**	7.1	18%
Contract price methanol (EUR/tonne)	**317**	300	6%

BRENT DATED IN USD AND NOK



Total revenues and other income increased from NOK 412 billion in 2006 to NOK 428 billion in 2007. 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% from USD 63.2/bbl in 2006 to USD 70.50/bbl in 2007, which was partly offset by the weakening of the average USD exchange rate by almost 9% from USDNOK 6.42 in 2006 to USDNOK 5.86 in 2007.

Cost of goods sold increased from NOK 383 billion in 2006 to NOK 402 billion in 2007. This was primarily due to increased crude oil prices and volumes purchased.

Operating, selling and administrative expenses increased by 3% in 2007 compared with 2006, mainly due to provisions for pension liabilities of NOK 0.7 billion largely related to early retirement. The whole amount is included in the restructuring costs relating to the merger and charged to income.

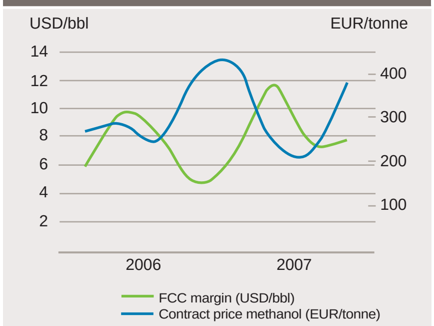
Depreciation, amortisation and impairment totalled NOK 2.8 billion in 2007, compared with NOK 2.3 billion in 2006. The increase was mainly due to an increase in impairment loss in Energy & Retail Sweden, from NOK 0.2 billion in 2006 to NOK 0.95 billion in 2007, NOK 0.5 billion of which is included in restructuring costs relating to the merger and charged to income.

In 2007, **net operating income** was NOK 3.8 billion, compared with NOK 7.3 billion in 2006. The difference was mainly due to increased early 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, a gain of NOK 0.6 billion in 2006 on the sale of our retail business in Ireland, and impairment loss and provisions of NOK 0.5 billion due to weak market conditions and restructuring of the retail business in Sweden.

Oil Sales, trading and supply

In 2007, net operating income was NOK 1.3 billion, compared with NOK 2.2 billion in 2006. The decrease in 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 Contract price on methanol

Manufacturing

In 2007, net operating income was NOK 3.3 billion, compared with NOK 4.4 billion in 2006. The decrease in 2007 was mainly due to lower regularity and higher operating costs due to turnaround activities. The lower USDNOK 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 income was NOK 0 billion in 2007, compared with NOK 0.6 billion in 2006. We experienced increased revenues during 2007, mainly due to 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%. The decrease in total net income was mainly due to increased impairment loss and provisions of NOK 0.6 billion in 2006 and NOK 1.1 billion in 2007, due to weak 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.

4.1.7.2 Outlook

Oil sales, trading and supply

The year 2007 was one of the most volatile periods in the product, gas liquids and crude oil markets. High prices were experienced during the year and we believe that prices will remain high and volatile at least in the near term.

Manufacturing

The outlook for the refinery industry continues to be good and high utilisation is expected. Significant new refining capacity, however, is expected to come on stream over the next few years. Combined with lower global economic growth, this new capacity is expected to have a negative impact on margins in the industry. However, profitability will very much depend on our ability to utilise the available feedstock and deliver the optimal product qualities. The average crude oil is getting heavier and more sour, while product specifications have become more stringent. Both factors require additional processing flexibility and capacity. Fuel oil conversion is expected to increase, and bio-components are expected to increase their market share. After heavy cost-cutting in the 1990s, recent high margins have increased the focus on reliability and utilisation. Combined with high pressure in the labour and contractor markets, the cost trend has changed, and maintenance and upgrading is expected to require continued management attention. The high energy costs could also make new energy efficiency initiatives more attractive.

Methanol prices are expected to return to a moderate level as new capacity in stranded gas areas becomes available. Europe is expected to continue to be a net importer of methanol, and European producers will therefore have a geographical advantage.

Energy and retail

The main growth in Energy and retail is expected to come from transport fuel, largely due to growth in diesel, and convenience, with a new indoor food range concept and lean operation.

Subject to EU Commission approval, the acquisition of Jet in Scandinavia will allow us to strengthen our Scandinavian retail position.

We have entered the St. Petersburg market in Russia, reinforcing our long-term ambition of sales growth in Eastern Europe. We already have a strong foothold in the Baltic countries and are expanding in Poland.

We believe that use of heavy oil products in the stationary carries 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

The years ended 31 December 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 loss before financial items, income taxes and minority interest of NOK 3.4 billion in 2007, compared with a loss of NOK 1.9 billion in 2006. The increase is primarily due to provisions made related to early retirement and pension benefits.

4.1.9 Reported volumes

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 volumes as a percentage of 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, **produced volumes** is 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 production 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, whereas it is not applicable in most concessionary regimes, such as those in Norway, the UK, Canada and Brazil.

Proved reserves are entitlement volumes recognised as reserves pursuant to SEC guidelines. They represent volumes that with reasonable certainty will be produced and to which we will have entitlement in the future. See the supplementary information in the financial statements on oil and gas producing activities for details about how we measure and report proven reserves.

4.2 Liquidity and capital resources

(in NOK million)	For the year ended 31 December 2007	2006
ASSETS		
Non-current assets		
Property, plant and equipment	**278,352**	272,163
Intangibles	**44,850**	31,205
Investment in associates	**8,421**	8,556
Deffered tax assets	**793**	808
Pension assets	**1,622**	1,113
Non-current financial investments	**15,266**	14,012
Der. fin. instr. non-current assets	**609**	450
Non-current financial receivables	**3,515**	4,341
Total non-current assets	**353,428**	332,648
Current assets		
Inventories	**17,696**	15,256
Trade and other receivables	**68,216**	80,954
Accounts receivable related parties	**1,162**	92
Derivative fin. instr. - current assets	**21,093**	21,323
Current financial investments	**3,359**	1,032
Cash and cash equivalents	**18,264**	7,518
Total current assets	**129,790**	126,175
TOTAL ASSETS	**483,218**	458,823
EQUITY AND LIABILITIES		
Equity		
Paid-in capital	**48,977**	49,047
Retained earnings	**140,909**	122,153
Other reserves (OCI)	**(12,611)**	(3,367)
Total shareholders' equity	**177,275**	167,833
Minority interest	**1,792**	1,574
Total equity	**179,067**	169,407
Non-current liabilities		
Non-current financial liabilities	**44,373**	49,215
Deferred tax liabilities	**67,477**	72,084
Net pension liab.-underfunded pens.plans	**19,092**	11,028
Non-current provisions	**43,845**	42,173
Total non-current liabilities	**174,788**	174,566
Current liabilities		
Trade and other payables	**51,695**	48,044
Acc. payable - related parties	**12,929**	7,551
Income taxes payable	**50,941**	47,149
Current financial liabilities	**6,166**	5,557
Der. fin. instr. current liabilities	**7,632**	6,549
Total current liabilities	**129,363**	114,850
Total liabilities	**304,151**	289,416
TOTAL EQUITY AND LIABILITIES	**483,218**	458,823

Other financial information	For the year ended 31 December 2007	2006
Net debt to capital employed (GAAP basis) [(1)]	**13.90%**	21.40%
Net debt to capital employed [(2)]	**12.40%**	20.50%
After-tax return on average capital employed (GAAP basis) [(3)]	**17.70%**	22.70%
After-tax return on average capital employed [(4)]	**19.90%**	22.90%

(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.

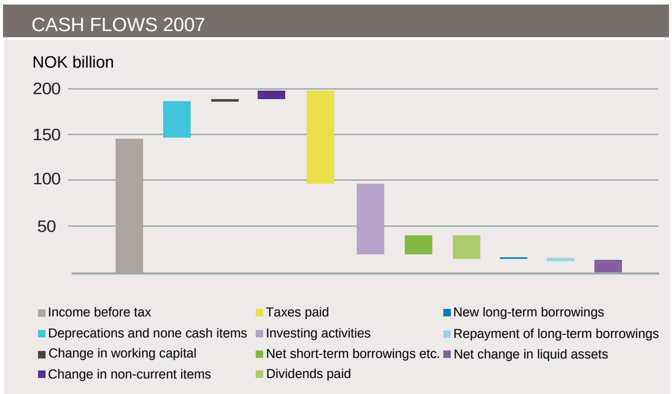
(2) As adjusted. In order to calculate the net debt to capital employed ratio that our management makes use of internally and which we report to the market, we make adjustments to capital employed as it would be reported under GAAP to adjust for project financing exposure that does not correlate to the 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 percentage)	For the year ended 31 December 2007	2006
Ratio of earnings to fixed charges	**20.7%**	19.8%

Based on IFRS. For the purpose of these ratios, earnings consist of the income before (i) tax, (ii) minority interest, (iii) amortisation of capitalised interest and (iv) fixed charges (which have been adjusted for capitalized interest) and after adjustment for unremitted earnings from equity accounted entities. Fixed charges consist of interest (including capitalised interest) and estimated interest within operating leases.



Cash flows from operating activities

Our primary source of cash flow consists of funds generated from operations. Net funds 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.

Cash flows used in investing activities

Net cash flows used in investing activities amounted to NOK 75.1 billion in 2007, compared with NOK 57.2 billion in 2006.

Gross investments, defined as additions to property, plant and equipment (including intangible assets and long term share investments) and capitalised exploration expenditure, amounted to NOK 75.0 billion in 2007, compared to NOK 64.3 billion in 2006. Gross investments in 2007 were NOK 31.1 billion, NOK 36.2 billion, NOK 2.1 billion and NOK 4.8 billion in Exploration & Production Norway, International Exploration & Production, Natural Gas and Manufacturing & Marketing, respectively.

Gross investments (in NOK billion)	For the year ended 31 December 2007	2006	Change
E&P Norway	**31.1**	29.2	6%
International E&P	**36.2**	28.9	25%
Natural Gas	**2.1**	3.2	(34%)
Manufacturing & Marketing	**4.8**	2.5	93%
Other	**0.8**	0.5	63%
Total gross investments	**75.0**	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 2007	2006
Cash flows to investments	**75.1**	57.2
NCS portfolio transactions	**0.0**	0.1
Capital leases	**0.0**	2.4
Proceeds from sales of assets	**1.1**	3.4
Other changes in long-term loans granted and liabilities joint-venture	**(1.2)**	1.2
Gross investments	**75.0**	64.3

Cash flows used in financing activities

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 at 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 NOK 25.5 billion at 31 December 2007, compared to NOK 43.8 billion at 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), credit rating and access to capital markets, we have sufficient liquidity and working capital to meet our present and future requirements. Our sources of liquidity are described below.

Liquidity

Our cash flow from operations is highly dependent on oil and gas prices and our levels of production, and it is only influenced to a small degree by seasonality and maintenance turnarounds. Fluctuations in oil and gas prices, which are outside our control, will cause changes in our cash flows. We will use available liquidity to finance Norwegian petroleum tax payments (due on 1 April 1 and 1 October 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.

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 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.

As of 31 December 2006, we had liquid assets of NOK 8.6 billion, including NOK 7.5 billion in cash and cash equivalents and NOK 1.1 billion of current financial investments (domestic and international capital market investments). Approximately 20% of our liquid assets were held in NOK-denominated assets, 67% in USD and 13% in other currencies, before the effect of currency swaps and forward contracts.

Compared to year end 2006, current financial investments increased by NOK 2.3 billion during 2007, and cash and cash equivalents increased by NOK 10.8 billion. The increase in liquid assets during 2007 was mainly due to a higher oil price, but it was somewhat offset by the weakening of the USD in relation to NOK during 2007.

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

As of 31 December 2007, 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 2007, no amounts had been drawn under the facility. In April 2007, we drew down a line of credit established in our favour on a bilateral basis by an international financial institution. The loan was denominated in USD and has a final maturity of five years.

Non-current financial liabilities
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 USDNOK exchange rate.

Net non-current financial liabilities amounted to NOK 25.5 billion at 31 December 2007, compared with NOK 43.8 billion at 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 Use and Reconciliation of Non-GAAP Financial 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 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.

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 13.9% in 2007, compared with 21.4% in 2006. See report section Use and Reconciliation of Non-GAAP Financial Measures - Net debt to capital employed ratio for more information.

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 2 billion and USD 3 billion, respectively), and through draw-downs under committed credit facilities and credit lines. Apart from the credit line drawn down in April 2007 described above, no material long-term borrowing took place in 2007.

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 1.7 billion in 2007 and NOK 0.1 billion in 2006. We repaid approximately NOK 2.9 billion in 2007and NOK 1.4 billion in 2006.

The company's central finance function manages the funding, liability and liquidity activities at group level based on our adopted financial policies.

4.2.1 Table of principal contractual obligations and other commitments

The following table summarises our principal contractual obligations and other commercial commitments as of 31 December 2007. The following 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 Risk review - Market risk - Quantitative and Qualitative Disclosures about Market Risk for more information.

Payment due by period (in NOK million)	Less than 1 year	1-3 years	4-5 years	More than 5 years	Total
	For the year ended 31 December				
Non-current liabilities including financial lease obligations	-	8,097	9,337	26,939	44,374
Operating lease obligations	10,892	30,276	5,344	7,844	54,356
Transport capacity, terminal capacity and similar obligations	8,500	20,713	5,993	37,455	72,661
Total contractual obligations	19,392	59,086	20,674	72,238	171,391

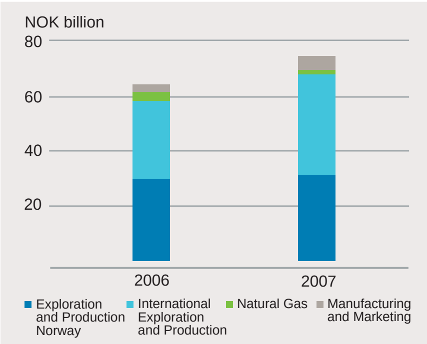
Non-current debt in the above table represents principal payment obligations. For information on interest commitments relating to long-term debt, reference is made to Note 20 - Financial liabilities and Note 24 - Leases to our Consolidated Financial Statements included this report.

Contractual obligations in respect of capital expenditures, acquisitions of intangible assets and construction in progress amounted to NOK 27.8 billion as of 31 December 2007, of which payments of NOK 13.2 billion are due within one year.

The group's projected pension benefit obligation was NOK 52.8 billion and the fair value of plan assets amounted to NOK 35.2 billion as of 31 December 2007. Unrecognised actuarial gains and losses and unrecognised prior service cost amounted to NOK 0.4 billion as of 31 December 2007 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 2007, the pension premium fund amounts to NOK 7.3 billion. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. The company contribution in 2007 was NOK 3.4 billion (exclusive of payroll tax), of which NOK 1.4 billion was a voluntary payment to the premium fund. The expected company contribution for 2008 is NOK 2.2 billion.

4.2.2 Investments

INVESTMENT BY SEGMENT



Our investments have increased due to more complex and challenging projects, expensive inorganic growth and cost increases due to a tight supplier market.

Capital expenditure

Our capital expenditure in our four principal business segments in 2006 and 2007 is described below, including the allocation per segment as a percentage of gross investments.

Capital expenditure is expected to amount to approximately NOK 75 billion in 2008 and NOK 80 billion in 2009.

We experienced a step-up in exploration activities in both 2006 and 2007. Exploration expenditure in 2007 amounted to NOK 14.2 billion, compared to NOK 13.4 billion in 2006. Exploration expenditure is expected to further increase to approximately NOK 18 billion in 2008. 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 Critical accounting judgements and key sources of estimation uncertainty - Exploration and leasehold acquisition costs for further discussion.

Gross investments (in NOK billion)	2007	of total	2006	of total
	For the year ended 31 December			
E&P Norway	**31.1**	**41%**	29.2	45%
International E&P	**36.2**	**48%**	28.9	45%
Natural Gas	**2.1**	**3%**	3.2	5%
Manufacturing & Marketing	**4.8**	**6%**	2.5	4%
Other	**0.8**	**1%**	0.5	1%
Total gross investments	**75.0**	**100%**	64.3	100%

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 2008 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 sections described under Financial performance.

E&P Norway. A substantial proportion of our 2008 capital expenditure is allocated to the ongoing development projects on Gjøa, Vega, Skarv, Alve, Morvin and Tyrihans, as well as the late-life projects on Statfjord and Gullfaks.

International E&P. We currently estimate that a substantial proportion of our 2008 capital expenditure will be allocated to the following ongoing and planned development projects: Agbami in Nigeria, ACG and Shah Deniz in Azerbaijan, Saxi Batique in Angola, South Pars in Iran, with planned start-up of production in 2008; Tahiti in the Gulf of Mexico and Corrib in Ireland, with planned production start-up in 2009, and Leismer in Canada and Peregrino in Brazil, with planned production start-up in 2010.

Natural Gas. In 2007 we finished the northern section of Langeled and the Tampen link pipeline. In addition, three LNG vessels and associated LNG companies were transferred from E&P Norway's assets to Natural Gas's assets with effect from 1 January 2007. We will continue to focus on increasing the capacity and flexibility of our gas transportation and processing infrastructure. This will be done through the expansion of the Kårstø processing plant, the Aldbrough gas storage project on the east coast of England and other investments.

Manufacturing & Marketing. We are focusing our capital expenditure on our retail network and on upgrading our refineries to increase flexibility and increase the value of the refined products. 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, which StatoilHydro can take over after 20 years, free of charge. We and our partners at Mongstad and on Troll will invest NOK 2.7 billion in a gas pipeline from Kollsnes to Mongstad and refinery modifications in connection with the CHP plant. In addition to the CHP project, the main focus at Mongstad in the next three years will be on improvements to infrastructure.

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

See report section Operational review - Related party transactions and report section Shareholder information - Major Shareholders, for a description of certain agreements we have entered into with the Norwegian State.

On 18 December 2006, Statoil and Norsk Hydro ASA announced that their respective boards of directors had agreed to a merger of Norsk Hydro's oil and gas activities and certain other related activities with Statoil. On 1 October 2007, the merger was completed (with effect from 1 January 2007), following which Statoil changed its name to StatoilHydro ASA.

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 gas 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.

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 represented 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 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

Our results have in recent years 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, whereas 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 Financial performance - High activity level in new organisation for details. As measured by the general consumer price index, inflation in Norway for the years ending 31 December, 2007 and 2006 was 0.9% and 2.6%, respectively.

4.2.5 Critical accounting judgements and key sources of estimation uncertainty

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 judgment 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 we have made in the process of applying the accounting policies and have the most significant effect on the amounts recognised in the financial statements

Method of accounting applied for merger with the oil and gas assets of Norsk Hydro
The merger between Statoil ASA and the oil and gas assets of Norsk Hydro has been accounted for using the carrying amounts of the assets and liabilities. When making this judgement the group considered firstly whether the Statoil ASA and the oil and gas assets of Norsk Hydro 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 reflecting all financial reporting as if such combination had existed for all periods presented. See note 2 Significant accounting policies-Basis for preparation and note 3 Merger with Hydro Petroleum for details on the merger and how it has been accounted for.

Revenue recognition - gross versus net presentation of traded SDFI volumes of oil and gas production
We market and sell the Norwegian State's share of oil and gas production from the NCS. We include the costs of purchase and proceeds from the sale of the SDFI oil production in Cost of goods sold and Revenue, respectively. In making the judgment we 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.

We also sell, in our 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 financial statements. In making the judgment we 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.

Key sources of estimation uncertainty
The preparation of consolidated financial statements require that management make estimates and assumptions.

The matters described below are considered to be the most important in understanding the judgments 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. Oil and gas reserves have been estimated by internal experts in accordance with industry standards under the requirements of the U.S. Securities and Exchange Commission (SEC). An independent third party has evaluated our 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.

Reserve estimates are used when testing upstream assets for impairment. Proved and proved developed reserves are used when calculating the unit of production rates used for depreciation, depletion, and amortisation. 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 and for decommissioning and removal provisions, 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 depreciation and amortisation or impairment charges. See note 32 Supplementary oil and gas information to our Consolidated financial statements included in this report for details.

Exploration and leasehold acquisition costs. Our accounting policy is to capitalise the costs of drilling exploratory wells pending determination of whether the wells have found proved oil and gas reserves. We also capitalise 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.

The following table itemises the ageing and categories of capitalised exploration expenditures and thus illustrates the risk profile of the capitalised amount as per 31 December 2007:

Capitalised exploratory drilling expenditures	in NOK million	Number of wells
Exploratory well expenditures that have been capitalised for a period of one year or less (A)	6,230	56
Exploratory well expenditures that have been capitalised for a period greater than one year, aged (B)		
Completed in 2006	2,092	23
Completed in 2005	783	16
Completed in 2004	222	4
Completed in 2003	177	9
Completed in 2002	101	6
Completed in 2001	284	3
Completed in 2000	0	0
Completed in 1999	42	3
Total	3,701	64
Exploratory well expenditures that have been capitalised for a period greater than one year, by category (B)		
Wells where additional drilling efforts are underway or firmly planned in the near future	1,483	16
Wells with economic reserves, development decision planned in the near future	1,868	39
Wells with economic reserves, development decision planned in the near future, subject to negotiations	350	9
Total	3,701	64
Total of capitalised exploratory drilling expenditures (A+B)	9,932	120

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 license or a development decision is planned in the near future.

Impairment/reversal of impairment. We have 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 judgment and may to a large extent depend upon the selection of key assumptions about the 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 judgment 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. See note 11 - Property, plant and equipment to our Consolidated financial statements included in this report for details of impairments recognised in the period.

Decommissioning and asset retirement obligations. We have 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. 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, heavy lift vessels and currency rates 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 judgment. See note 22 - Asset retirement obligations and other provisions to our Consolidated financial statements included in this report for details of estimated obligations and the changes therein.

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 makes 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. See note 21 Pension obligations in the F-pages for details of estimated pension obligations, pension assets and the sensitivities to changes in assumptions.

Derivative financial instruments and hedging activities. We recognise all derivatives on the balance sheet at fair value. Changes in fair value of derivatives that do not qualify as hedges are included in income.

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 have material effects on the internally computed fair value of derivative contracts, particularly long-term contracts, resulting in corresponding income or loss in the income statement. See note 28 - Financial instruments by category and note 29 - Financial instruments and hedging activities in our Consolidated financial statements included in this report for details of recognised assets and liabilities and sensitivities, respectively, related to financial instruments and hedging activities.

Income tax. We annually incur 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. See note 9 - Income taxes in our Consolidated financial statements included in this report for details of amounts recognised as income tax assets, liabilities and expense.

4.2.6 Off balance sheet arrangements

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 Table of principal contractual obligations and other commitments for more information.

We are not party to any off-balance sheet arrangements such as the use of Variable Interest Entities.

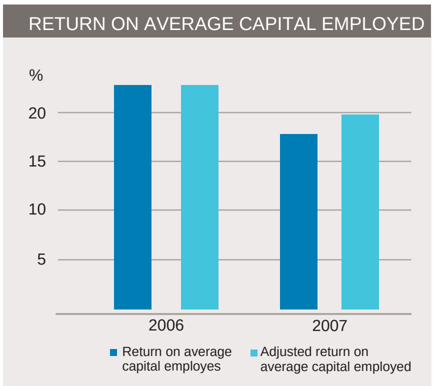
4.3 Use and reconciliation of Non-GAAP measures

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 average capital employed after tax (ROACE)



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 17.9% in 2007, compared with 22.9% in 2006. The decrease was mainly due to higher operating expenses as well as higher capital employed, and it was partly offset by increased net financial income. Adjusted for the effects of restructuring costs and other costs arising from the merger, ROACE was 19.9% in 2007, compared with 22.9% in 2006. ROACE is defined as a non-GAAP financial measure.

Calculation of numerator and denominator used in ROACE calculation (in NOK million, except percentages)	For the year ended 31 December 2007	2006
Net income for the last 12 months	**44,641**	51,847
After-tax net financial items for the last 12 months	**(7,157)**	(5,072)
Net income adjusted for financial items after tax (A1)	**37,484**	46,775
Adjustment for restructuring costs and other costs arising from the merger	**4,212**	0
Net income adjusted for restructuring costs and other costs arising from the merger (A2)	**41,696**	46,775
Calculated average capital employed		
Average capital employed before adjustments (B1)	**211,806**	206,100
Average capital employed (B2)	**208,857**	204,408
Calculated ROACE		
Calculated ROACE based on average capital employed before adjustments (A1/B1)	**17.7%**	22.7%
Calculated ROACE based on average capital employed (A1/B2)	**17.9%**	22.9%
Calculated ROACE based on average capital employed and one-off effects (A2/B2)	**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. 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 USDNOK 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.

Produced volumes used in the calculation of the normalised production cost per boe have been adjusted for PSA effects. The group's 2007 target for production cost per boe is based on an oil price of USD 60 per bbl. Higher oil price levels affect the production entitlements negatively, and hence the production unit cost.

Entitlement volumes are highly affected by production sharing agreements (PSA effects). On average, the total daily difference between entitlement and equity volumes was 115 mboe in 2007 and 70 mboe in 2006. Using equity volumes in the denominator in the calculation of production costs per boe results in an average production cost (not normalised) of NOK 41.4 per boe in 2007 compared to NOK 27.3 per boe in 2006.

Production cost per boe	For the year ended 31 December 2007	2006
Total production costs last 12 months (in NOK million)	**27,776**	17,675
Produced volumes last 12 months (million boe)	**629**	623
Average USDNOK exchange rate last 12 months	**5.86**	6.41
Production cost (USD/boe)	**7.70**	4.44
Calculated production cost (NOK/boe)	**44.1**	**28.4**
Normalisation of production cost per boe		
Total production costs last 12 months (in NOK million)	**27,776**	17,675
Production costs last 12 months International E&P (in USD million)	**662**	498
Normalised exchange rate (USDNOK)	**6.00**	6.00
Production costs last 12 months International E&P normalised at USDNOK 6.00	**3,972**	2,987
Production costs last 12 months E&P Norway (in NOK million)	**23,919**	14,488
Total production costs last 12 months in NOK million (normalised)	**27,891**	17,475
Production cost (NOK/boe) normalised at USDNOK 6.00	**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 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.

Calculation of capital employed and net debt to capital employed ratio (in NOK million)	For the year ended 31 December 2007	2006
Total shareholders' equity	**177,275**	167,833
Minority interest	**1,792**	1,574
Total equity and minority interest (A)	**179,067**	169,407
Short-term debt	**6,166**	5,557
Long-term debt	**44,373**	49,215
Gross interest-bearing debt	**50,539**	54,772
Cash and cash equivalents	**(18,264)**	(7,518)
Current financial investments	**(3,359)**	(1,032)
Cash and cash equivalents and current financial investments	**(21,623)**	(8,550)
Net debt before adjustments (B1)	**28,916**	46,222
Other interest-bearing elements	**-**	-
Marketing instruction adjustment	**(1,434)**	-
Adjustment for project loan	**(2,020)**	(2,443)
Net interest-bearing debt (B2)	**25,461**	43,779
"Normalisation for cash-build up before tax payment (50% of tax payment)"	**-**	-
Net interest-bearing debt (B3)	**25,461**	43,779
Calculation of capital employed		
Capital employed before adjustments to net interest-bearing debt (A+B1)	**207,983**	215,629
Capital employed before normalisation for cash build-up for tax payment (A+B2)	**204,528**	213,186
Capital employed (A+B3)	**204,528**	213,186
Calculated net debt to capital employed		
Net debt to capital employed before adjustments (B1/(A+B1))	**13.9%**	21.4%
Net debt to capital employed before normalisation for tax payment (B2/(A+B2)	**12.4%**	20.5%
Net debt to capital employed (B3/(A+B3))	**12.4%**	20.5%

4.4 Implementation of International Financial Reporting Standards (IFRS)

In accordance with the requirements of Norwegian and European Union (EU) regulations, StatoilHydro has for 2007 prepared its first set of consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the EU. The accounting policies applied by the group also comply with IFRS as issued by the International Accounting Standards Board (IASB).

These IFRS have been applied consistently to all periods presented in the consolidated financial statements and when 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.

5 Risk review

5.1 Risk factors

5.1.1 Risks related to our business

The failure to integrate the operations of the merged company successfully and on a timely basis could reduce our profitability and adversely affect our share price.

Achievement of the benefits we anticipate from the merger will depend in part upon whether the operations and the personnel of Statoil and Norsk Hydro's oil and gas business can be integrated in an efficient, effective and timely manner. If we are not successful in this integration, our financial results could be adversely impacted.

The success of the merger will also depend, in part, on our ability to effectively pursue additional growth opportunities, achieve improved performance, and realise efficiencies, synergies, cost savings and certain other benefits. Even if we are successfully able to combine our operations, it may not be possible to realise the full benefits that we currently anticipate to result from the merger, or realise these benefits within the time frame that is currently expected. In addition, 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 integration, the impact of competition and other risk factors relating to the industry.

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. A 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. For an analysis of the impact on net operating income of changes in oil and gas prices, see the Market Risk section 5.2 below. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically or reduce the economic viability of projects planned or in development.

Exploratory 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, Alaska, onshore Algeria and Libya, as well as offshore Angola 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. 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, than our financial or human resources permit. For more information on the competitive environment, see Operational Review-Competition section 3.13.

Since we face a variety of challenges in executing our strategic objective of successfully exploiting growth opportunities available to us, the growth of our business may be compromised if we are unable to execute our strategy, and our financial and production targets may be revised as a result of acquisitions made in accordance with our strategy.

An important element of our strategy is to continue to pursue attractive growth opportunities available to us, both in enhancing 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. 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; and
- arrange financing, if necessary.

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 targets 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. It is likely that such acquisitions will be in the exploratory or development phase and not in the production phase, which will have a material adverse effect on our net return in proportion to our average capital employed. 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 targets with respect to unit production costs and production.

In addition, the pursuit of acquisitions or new business opportunities could divert financial and management resources away from our day-to-day operations to the integration of acquired operations or properties. We may require additional debt or equity financing to undertake or consummate future acquisitions or projects, and such financing may not be available on terms satisfactory to us, if at all, and it may, in the case of equity, be dilutive to our earnings per share.

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. For example, we encountered cost increases and construction and operational challenges in the Snøhvit project that have still not been resolved.

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.

Many of our mature fields are producing increasing quantities of water with oil and gas. Our ability to dispose of this water in acceptable ways may have an impact on our oil and gas production.

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 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. For more information regarding recent developments in Venezuela relating to the Sincor project, see Operational Overview-International Exploration and Production, section 3.2.6.2.1. 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 governmental and regulatory framework is subject to unexpected change or where the enforcement of contractual rights is uncertain. 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 license 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 Iran could lead to US sanctions.

In August 1996, the United States adopted the Iran and Libya Sanctions Act, referred to as ILSA, which authorises the President of the United States to impose sanctions (from a list that includes denial of financing by the export-import bank and limitations on the amount of loans or credits available from US financial institutions) against persons found by the President to have knowingly made investments in Iran of USD 20 million or more in any 12-month period that directly and significantly contribute to the enhancement of such countries' ability to develop their petroleum resources. ILSA was adopted with the objective of denying Iran and Libya the ability to support acts of international terrorism and fund the development or acquisition of weapons of mass destruction. In April 2004, the application of ILSA with respect to Libya was terminated and in September 2006, ILSA's name was changed to the Iran Sanctions Act of 1996 (ISA).

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 2007, we had invested a total of USD 103.7 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 2007, StatoilHydro had invested a total of USD 123.7 million in 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. The Khorramabad Exploration Block is in the exploration phase. By the end of 2007, StatoilHydro had not invested any amounts in the exploration or development of the Khorramabad Exploration Block. 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 2007, we had invested USD 69.6 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 2007 represented less than 0.08% of our total assets as of December 31, 2007.

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 or operational catastrophes.

Exploration for and the production of oil and natural gas is hazardous, and natural disasters, operator error or other occurrences can result in oil spills, 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. 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.

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 a significant portion of our operating expenses and income taxes accrue in Norwegian kroner, reflecting our operations on the NCS. Fluctuations between the US dollar and Norwegian kroner may adversely affect our business. While an increase in the value of the US dollar in relation to the Norwegian kroner can be expected to increase our reported earnings, such an increase would also be expected to increase our operating expenses and the value of our debt, which would be recorded as a financial expense, and, accordingly, would adversely affect our net income. See the Market Risk section below.

We are exposed to risks relating to trading and supply activities.

Statoil 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 Statoil believes it has established appropriate risk management procedures, trading activities involve elements of forecasting and Statoil bears the risk of market movements - the risk of significant losses if prices develop contrary to expectations - and the risk of default by counterparties. See the Market Risk section 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.

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 the 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.

In 2003, a new Gas Directive approved by the EU accelerated the requirements relating to opening markets, allowing both large users and households to freely choose their supplier earlier than previously anticipated. The new directive also stipulated that all transportation of natural gas should be based on a system of open access with regulated tariffs. The new Gas Directive was implemented in Norwegian legislation in June 2006.

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 Operational Review-Regulation section 3.12.4.

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.

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 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. Reductions of up to 7.5% have been imposed in the past. By royal decree of 19 December 2001, the Norwegian government decided that Norwegian oil production was to be reduced by 150,000 barrels per day from 1 January 2002 until 30 June 2002. This amounted to a roughly 5% reduction in output. Furthermore, in the production licences in which the State's Direct Financial Interest (SDFI) holds an interest, the Norwegian State retains the ability to direct petroleum licensees' 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 Item Operational Review-Regulation, section 3.12.6.

5.1.3 Risks related to our ownership by the 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 Statoil and the SDFI's interest in NCS licenses 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 62.5% of our ordinary shares as at 31 December 2007 and has recently indicated that it intends to increase its shareholding to 67%. Although a two-thirds majority is required to determine matters submitted for a vote of shareholders, 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 Operational overview-Related Party Transactions.

5.2 Market risk

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.

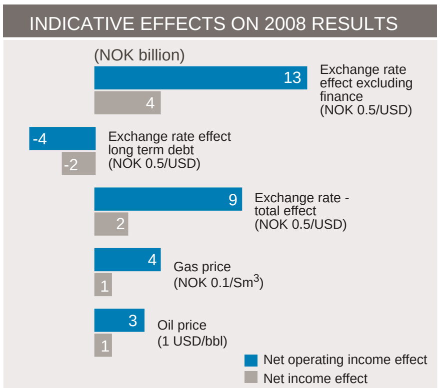
Our results will also be affected by trends in the international oil industry, including possible actions by governments and other regulatory authorities in the jurisdictions in which we operate, or possible or continued actions by members of the Organization of Petroleum Exporting Countries (OPEC) that affect price levels and volumes; refining margins; increasing cost of oilfield services, supplies and equipment; increasing competition for exploration opportunities and operatorships, and deregulation of the natural gas markets, 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 2007 and 2006.

Yearly average	2007	2006
Crude oil (USD/bbl Brent Blend)	**70.50**	63.20
Natural gas (NOK per scm) (1)	**1.69**	1.94
FCC margins (USD/bbl) (2)	**8.40**	7.10
USDNOK average daily exchange rate	**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, the FCC (refining) margins and the USDNOK exchange rate, if sustained for a full year, could impact our financial results, assuming activity at levels achieved in 2007.

The estimated sensitivity of each of the factors on our financial results have 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. However, because our outstanding debt is currently in USD, the benefit to StatoilHydro would be offset in the near term by an increase in the value of our debt, which would be recorded as a financial expense and, accordingly, would adversely affect our net income. A decrease in the exchange rate would have the opposite effect, and hence cause decreased earnings, which would be offset by financial income in the near term. Please see section Risk review-Market risk-Qualitative and quantitative disclosures about market risks below.

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 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 Financial performance-High activity level in new organisation-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 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.

5.2.1 Risk management

General information relevant to risks

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. Overall risk management means that 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

1. 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.
2. Tactical risks which are short-term trading risks based on underlying exposures managed by our principle business segment line managers, and
3. Insurable risks which 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).

StatoilHydro's activities expose it to various financial risks: market risk (including interest rate risk, currency risk, equity price risk, and commodity price risk), liquidity risk, and credit risk.

In 2007, StatoilHydro merged with Hydro Petroleum and as a result assumed various financial risks previously managed according to Hydro Petroleum's risk management objectives, policies and procedures. StatoilHydro's and Hydro Petroleum's management of these types of financial risks may have been different however StatoilHydro is not aware of significant differences for the periods presented. Effective 1 October 2007, all financial instruments and risks are managed in accordance with StatoilHydro's risk management objectives, policies and procedures.

Market risk management
We operate 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 on a long and short term basis, with focus on what is best for StatoilHydro in order to achieve optimal risk adjusted returns.

We have established an Enterprise-Wide Risk Management Programme, which establishes guidelines for entering into contractual arrangements (derivatives) to manage its commodity price, foreign currency rate, and interest rate risk. Within the programme, StatoilHydro has developed a comprehensive model, which encompasses our most significant market and operational risks and takes into account correlation, different tax regimes, capital allocation on various levels and value at risk, or VaR, figures on different levels, with the goal of optimising risk adjusted return.

We have used and intend to use financial and commodity-based derivatives to manage the risks in overall earnings and cash flows. We use swaps, options, futures, and forwards to manage our exposure to changes in the value of future cash flows primarily from future purchases and sales of crude oil and refined oil products. The term of the oil and refined oil products derivatives is usually less than one year. Natural gas and electricity swaps, options, forwards, and futures are likewise utilised to manage exposure to changes in the value of future sales of natural gas and electricity. These derivatives usually have terms of approximately three years or less. Swaps are used by to manage interest rate risk related to our long-term debt portfolio.

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 minimise the commodities price volatility and match costs with revenues, 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 International Petroleum Exchange (IPE) 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 IPE.

Currency and interest rate risk
We are subject to foreign exchange and interest rate risk which are assessed on a portfolio basis in accordance with approved strategies and mandates. In market risk management and in trading, we use only well-understood, conventional derivative instruments. These include futures and options traded on regulated exchanges, OTC swaps, options and forward contracts.

Fluctuations in exchange rates can have significant effects on our results. Our cash inflows are largely denominated in or driven by U.S. dollars while our cash outflows, such as operating expenses and taxes payable, are to a large extent in NOK. Accordingly, our exposure to foreign currency rates exists primarily with U.S. dollars versus NOK. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into U.S. dollars.

The existence of assets earning and liabilities owing variable rates of interest expose us to the risk of 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 funding costs 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.

Interest rate management
We principally manage our interest rates on the basis that the non-current debt portfolio shall have 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 shall be between 0 and 0.5 per cent. Exceptions can from time to time be approved if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

Liquidity risk management
The purpose of liquidity management and short term funding is to make certain that StatoilHydro at all times has sufficient funds available to cover financial obligations.

StatoilHydro's business activities often generate, on a monthly basis, a positive cashflow from operations. However, in months when taxes are paid (April and October) or annual dividend is paid (typically in May/June) cashflows are typically limited.

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 programs or under documentation established ad hoc. These funding programs are as follows:

- A USD 2 billion US commercial paper programme. This is the most flexible program which is 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 program.
- 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 shall maintain a minimum liquidity reserve.

Liquid assets as at 31 December

(in NOK million)	2007	2006
Cash and cash equivalents	18.3	7.5
Financial investments	3.3	1.0
Total liquid assets	21.6	8.5

Funding and liability management
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 maintains 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. The stated objective is to have a credit 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.

In order to control our refinancing risk the maturity and redemption profile of non-current debt issued shall be 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 indicates that the non-compliance is likely 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 Notes to financial statements 20, Financial liabilities.

Credit risk management

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 7.5 billion in 2007 and NOK 6.9 billion in 2006), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents. StatoilHydro attempts to significantly reduce this exposure through its credit risk management policies and procedures.

We manage credit risk concentration with respect to financial instruments by holding only investment grade securities distributed among a variety of selected issuers. A list of authorised investment limits by commercial issuer is maintained and reviewed regularly along with guidelines which include an assessment of the financial position of counter-parties as well as requirements for collateral.

Credit risk related to commodity-based instruments is managed by maintaining, reviewing and updating lists of authorised counter-parties by assessing their financial position. StatoilHydro frequently monitors credit exposure for each counter-party, establishes internal credit lines for the counterparty, and requires collateral or guarantees when appropriate under contracts and as required by internal policies. Collateral will typically be in the form of cash or bank guarantees from highly rated international banks.

Credit risk related to interest rate swaps and currency swaps, which are OTC transactions, is derived from the counter-parties to these transactions. Counter-parties are highly rated financial institutions. The credit ratings are at a minimum reviewed annually and counter-party exposure is monitored on a continuous basis to ensure exposure does not exceed credit lines and complies with internal policies. Non-debt-related foreign currency swaps usually have terms of less than one year, and the terms of debt-related-interest swaps and currency swaps are up to 22 years, in line with that of corresponding hedged or risk managed non-current debenture bonds or bank loans.

The credit risk concentration with respect to receivables is limited due to the large number of counter-parties spread worldwide in numerous industries.

The following table contains the fair market value of open non-exchange traded derivative assets split by our assessment of the counter-party's credit risk:

	At 31 December	
(in NOK million)	**2007**	**2006**
Counter-party rated:		
Investment grade, rated A or above	19,647	17,326
Other investment grade	928	1,805
Non-investment grade or not rated	689	416

As of 31 December 2007, NOK 2.8 billion in collateral is available to the Group to offset a portion of this credit exposure.

Credit rating categories in the table above are based on the our internal credit rating policies, and do not always correspond directly with ratings issued by the major credit rating agencies due to internal evaluation criteria. 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.

5.2.2 Quantitative and qualitative disclosures about market risk

Fair values of financial instruments by category

The tables below provide a comparison of carrying amounts and fair values of all the Group's financial instruments including derivative financial instruments.

			Fair value through profit or loss			
(in NOK million)	**Loans and receivables**	**Available-for-sale**	**Held for trading**	**Fair value option**	**Total carrying amount**	**Fair value**
31 December 2007						
Assets as per balance sheet						
Non-current financial investments	0	3,291	0	11,975	15,266	15,266
Non-current derivative financial instruments	0	0	609	0	609	609
Non-current financial receivables	3,515	0	0	0	3,515	3,515
Current trade and other receivables	69,378	0	0	0	69,378	69,378
Current derivative financial instruments	0	0	21,093	0	21,093	21,093
Current financial investments	0	0	3,359	0	3,359	3,359
Cash and cash equivalents	18,264	0	0	0	18,264	18,264
Total	91,157	3,291	25,061	11,975	131,484	131,484

			Fair value through profit or loss			
(in NOK million)	**Loans and receivables**	**Available-for-sale**	**Held for trading**	**Fair value option**	**Total carrying amount**	**Fair value**
31 December 2006						
Assets as per balance sheet						
Non-current financial investments	0	2,262	0	11,750	14,012	14,012
Non-current derivative financial instruments	0	0	450	0	450	450
Non-current financial receivables	4,341	0	0	0	4,341	4,341
Current trade and other receivables	81,046	0	0	0	81,046	81,046
Current derivative financial instruments	0	0	21,323	0	21,323	21,323
Current financial investments	0	0	1,032	0	1,032	1,032
Cash and cash equivalents	7,518	0	0	0	7,518	7,518
Total	92,905	2,262	22,805	11,750	129,722	129,722

Financial assets are measured at fair value or their carrying amounts reasonably approximate fair value. See note 2, Significant accounting policies, and note 29, Financial instruments and hedging activities, for further information regarding measurement of fair values.

(in NOK million)	Amortised cost	Fair value through profit or loss	Total carrying amount	Fair value
31 December 2007				
Liabilities as per balance sheet				
Non-current financial liabilities	44,373	0	44,373	47,278
Non-current derivative financial instruments	0	1	1	1
Current trade and other payables	64,624	0	64,624	64,624
Current financial liabilities	6,166	0	6,166	6,166
Current derivative financial instruments	0	7,632	7,632	7,632
Total	**115,163**	**7,633**	**122,796**	**125,701**
31 December 2006				
Liabilities as per balance sheet				
Non-current financial liabilities	49,215	0	49,215	53,014
Non-current financial instruments	0	66	66	66
Current trade and other payables	55,595	0	55,595	55,595
Current financial liabilities	5,557	0	5,557	5,557
Current derivative financial instruments	0	6,549	6,549	6,549
Total	**110,367**	**6,615**	**116,982**	**120,781**

Financial liabilities' carrying amounts reasonably approximate fair value except the fair values of non-current financial liabilities which have been determined by using year-end market interest rates to calculate discounted cashflows. See note 2, Significant accounting policies, and note 29, Financial instruments and hedging activities, for further information regarding measurement of fair values.

The following table includes amounts from the Statement of income related to financial instruments.

	Fair value through profit or loss			
(in NOK million)	Held for trading	Fair value option	Instruments at amortised cost	Available-for-sale assets
For the year ended 31 December 2007				
Net gains	0	0	0	129
Net losses	(1,689)	(263)	(245)	0
Total interest income	202	351	1,941	308
Total interest expense	0	0	(3,084)	0
Total	(1,487)	88	(1,388)	437
For the year ended 31 December 2006				
Net gains	5,577	620	412	0
Net losses	0	0	0	0
Total interest income	590	332	1,801	244
Total interest expense	0	0	(1,658)	0
Total	6,167	952	555	244

Dividend income is included with Total interest income. Foreign exchange gains or losses related to financial instruments are not included, see note 8, financial items, for additional information.

Fair value hedges

Fair value hedges are hedges of StatoilHydro's exposure to changes in the fair value of a recognised asset and liability or an unrecognised firm commitment. StatoilHydro has designated certain interest rate swaps as fair value hedges to hedge against changes in the fair value, due to changes in the interest rates, of certain parts of the Group's financial liabilities. There was no significant element of hedge ineffectiveness the year ended 31 December 2007. 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 risk of bonds subject to hedge accounting are presented below together with the related gains and losses.

(in NOK million)	Fair value	Gains (losses)
At 31 December 2007		
Hedging instruments	651	221
Hedged risk of bonds subject to hedge accounting	(724)	(212)
At 31 December 2006		
Hedging instruments	430	(459)
Hedged risk of bonds subject to hedge accounting	(512)	452

Fair value of derivative financial instruments and fixed rate interest bearing bonds

The Group recognises all derivative financial instruments in the balance sheet at fair value. Changes in the fair value of derivatives are included in the Statement of income either in revenue or in financial items. In some instances the carrying amount is assessed to be a reasonable approximation of fair value, the instrument is then recognised in the balance sheet at the carrying amount. For StatoilHydro this is the case for current trade receivables and payables. For more information about the methodology and assumption used when calculating the fair value of the financial instruments see note 2, Significant accounting policies.

The following table contains the carrying amounts and estimated fair values of derivative financial instruments including certain derivative commodity contracts, and the carrying amounts and estimated fair value of fixed rate interest bearing bonds. Commodity contracts capable of being settled by physical delivery of commodities (crude oil, refined products, natural gas and electricity) are excluded from the summary. Of the total ending balance at 31 December 2007 NOK 9.6 billion relates to certain earn-out agreements recognised as derivative financial instruments in accordance with IAS 39. At the end of 2006 NOK 6.7 billion was related to these agreements.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
At 31 December 2007			
Debt-related instruments	4,676	(125)	4,551
Non-debt-related instruments	1,802	(163)	1,639
Non-current fixed interest liabilities	0	(38,971)	(35,923)
Crude oil and Refined products	10,620	(1,446)	9,174
Gas and Electricity	599	(795)	(196)
At 31 December 2006			
Debt-related instruments	3,972	(413)	3,559
Non-debt-related instruments	2,057	(338)	1,719
Non-current fixed interest liabilities	0	(46,166)	(42,338)
Crude oil and Refined products	7,462	(681)	6,781
Gas and Electricity	1,646	(273)	1,373

The following table contains a reconciliation of changes in the fair values of all derivatives, except positions entered into and subsequently terminated during the course of 2007:

(in NOK million)	Commodity derivatives	Financial derivatives
Net fair value of derivative contracts oustanding at 31 December 2006	9,733	5,296
Contracts realised or settled during the period	(4,123)	(2,344)
Fair value of new contracts entered into during the period	(2,069)	2,693
Changes in fair value attributable to changes in valuation techniques or assumptions	(136)	563
Other changes in fair values	4,474	(18)
Net fair value of derivative contracts oustanding at 31 December 2007	7,879	6,190

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 27, 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 for 2007 and 2006 has been calculated by assuming a hypothetical across-the-board 10% change in all commodity prices. This does not take into account the term or historical relationships between the contractual price of the instrument and the underlying commodity prices or the expected correlation between risk categories. Therefore, in the event of an actual 10% change in all underlying prices, the change in the fair value of the derivative portfolio at the two respective year ends would typically be different from that shown below. In addition, there would be expected offsetting effects from changes in the fair value of our corresponding physical positions, contracts and anticipated transactions, which are not recorded at fair value, and are not reflected in the below table.

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

(in NOK million)	Fair value asset	Fair value liability	-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)

Where an active market exists, financial instruments are valued on the the basis of quoted information from the active market. The following table summarises the basis for fair value estimation and the maturity of such 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 2007					
Fair value based on prices quoted in an active market	906	1,731	178	2,108	4,923
Fair value based on price inputs from external sources	5	7	0	0	12
Fair value based on inputs from other sources	13	(1)	(1)	9,854	9,865
At 31 December 2006					
Fair value based on prices quoted in an active market	4,073	1,057	1,498	1,011	7,639
Fair value based on price inputs from external sources	239	278	0	(1,069)	(552)
Fair value based on inputs from other sources	59	217	(10)	7,666	7,932

Even though the major part of the fair value from certain earn out agreements are from observable external sources 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 price. When extrapolating the forward curve with inflation the fair value of the contracts included will increase by approximately NOK 2.5 billion. This increased change in fair value would be recognised in the Statement 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 above. Changes in the fair value of commodity-based financial instruments due to different assumptions made on future exchange rates and interest rates is deemed immaterial. See however text below under Interest and currency risk for details of aggregate effects of such sensitivities.

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 27, Financial risk management.

(in NOK million)	2007	2006
Less than 1 year	(5,279)	(4,575)
1 - 3 years	(2,094)	(1,815)
4 - 5 years	(113)	(98)
After 5 years	(147)	(127)
Derivative financial instruments	(7,633)	(6,615)

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 fair value of financial instruments related to our interest rate swaps, currency swaps and fixed interest non-current liabilities are specified in the table below:

(in NOK million)	Net fair value
At 31 December 2007	
Debt-related instruments	4,551
Non-debt related instruments	1,639
Non-current fixed interest liabilities	(38,971)
At 31 December 2006	
Debt-related instruments	3,559
Non-debt related instruments	1,719
Non-current fixed interest liabilities	(46,166)

The estimated loss that would be recognised in the Statement of income associated with a 10% adverse change in NOK currency rates would be approximately NOK 10.4 billion and NOK 7.6 billion as of 31 December, 2007 and 2006, respectively. A hypothetical one percentage point adverse change in interest rates would result in a loss, that would be recognised in the income statement, of NOK 2.7 billion and NOK 2.4 billion related to interest-bearing liabilities, investments in debt securities and related financial instruments as of 31 December, 2007 and 2006, respectively. These estimated currency and interest rate sensitivities are based on an uncorrelated loss scenario and actual results could vary due to assumptions used and because offsetting account correlations are not reflected within this analysis. All financial instruments included in the interest and currency rate sensitivity calculation have a linear sensitivity towards changes. Therefore a positive change in the NOK currency rates and interest rates would give a gain that would be recognised in the Statement of income, with the opposite values as the losses calculated for the negative changes.

StatoilHydro's cash flows are largely in US dollars, European euro and Norwegian kroner, but significant amounts are also Swedish kroner, Danish kroner and UK pounds sterling. The currencies in the debt portfolio are managed in connection with our expected future net cash flows per currency. The Group's debt, after considering currency swaps, is mainly in US dollars.

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-marketable 0-20% investments classified as Available for sale investments in accordance with IAS 39. These are recognised at fair value in the balance sheet with changes in the fair value recognised directly in equity.

Risk is estimated as the potential loss in fair value resulting from a hypothetical 10% adverse change in quoted market prices. Actual results may vary due to assumptions utilised and because correlation are not reflected within the analysis.

(in NOK million)	Fair value	-10% sensitivity	10% sensitivity
At 31 December 2007			
Fair value of marketable equity securities	4,230	(423)	423
Fair value of other non-marketable equity securities	3,291	(329)	329
At 31 December 2006			
Fair value of marketable equity securities	4,600	(460)	460
Fair value of other non-marketable equity securities	2,262	(226)	226

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 Horton Case

The Norwegian National Authority for Investigation and Prosecution of Economic and Environmental Crime (Økokrim) conducted an investigation concerning an agreement which StatoilHydro entered into in 2002 with Horton Investments Ltd for consultancy services in Iran. In June 2004, Økokrim informed StatoilHydro that it had concluded that StatoilHydro had violated the Norwegian Penal Code's prohibition on trading in influence, which became effective on 4 July 2003, and it imposed a penalty of NOK 20 million (USD 3 million). In October 2004, StatoilHydro agreed to accept the penalty without admitting or denying the charges by Økokrim.

On 13 October 2006, StatoilHydro announced that it had reached agreements with the US Securities and Exchange Commission (SEC), the U.S. Department of Justice (DOJ), and the United States Attorney's Office for the Southern District of New York (USAO). In the agreements with the DOJ and USAO, StatoilHydro has accepted a penalty of USD 10.5 million for having violated the U.S. Foreign Corrupt Practices Act (FCPA), and it has accepted responsibility for bribery in connection with the payments under the consultancy services contract with Horton Investments Ltd, for accounting for those payments improperly in its books and records, and for having insufficient internal controls in place to prevent the payments. The NOK 20 million (USD 3 million) fine paid to Økokrim has been deducted, so that the fine actually paid by StatoilHydro under this agreement is USD 7.5 million. In the agreement with the SEC, StatoilHydro has neither admitted nor denied the charges, but agreed to pay USD 10.5 million as disgorgement.

Since it first learned of the payments in September 2003, StatoilHydro has taken prompt and forceful steps to put new policies and practices in place designed to ensure the highest standards of transparency and ethical conduct. Among other actions, StatoilHydro retained outside counsel to conduct a thorough internal review and it adopted new stronger internal controls and new stricter ethical policies and practices. StatoilHydro has cooperated fully with the SEC, DOJ and USAO throughout their inquiries and shared the results of the internal review with the agencies.

The settlement takes the form of a three-year deferred prosecution agreement with the DOJ and USAO and a Cease and Desist Order with the SEC. In the deferred prosecution agreement, StatoilHydro has consented to the filing with the United States Court for the Southern District of New York of a criminal information charging violations of the anti-bribery and books and records provisions of the FCPA. If StatoilHydro fulfils its obligations under the deferred prosecution agreement for three years, the criminal charges will be dismissed and the Horton case will be closed.

The Libya case

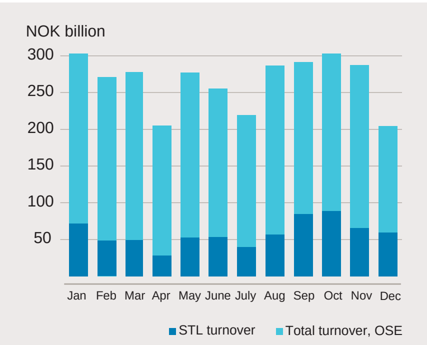
StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's operations in Libya that could be in conflict with applicable Norwegian and US anti-corruption legislation. Hydro's petroleum activities in Libya were transferred to StatoilHydro as of 1 October 2007 as part of the merger with Hydro's petroleum business. Following a preliminary assessment by StatoilHydro's corporate audit function, Chief Executive Helge Lund resolved in consultation with the StatoilHydro board to initiate an external review of the relevant aspects. The purpose is to determine the facts relevant to applicable Norwegian and US anti-corruption legislation to which StatoilHydro may be subject as a result of those operations. The US law firm Sidley Austin LLP is in the process of carrying out the review together with Norwegian law firm Simonsen Advokatfirma DA, supported by StatoilHydro's corporate audit function. Other consultancy agreements relating to Hydro's international petroleum operations will also be reviewed. Both Hydro and StatoilHydro are cooperating on securing the documentation and information required to establish the facts of the matter.

6 Shareholder information

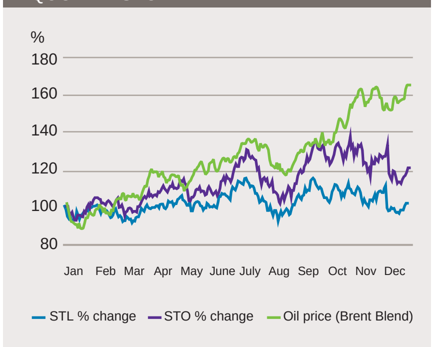
StatoilHydro share	2007	2006	2005	2004	2003
Share price STL high (NOK)	**191.50**	210.50	166.50	103.50	75.25
Share price STL low (NOK)	**151.50**	147.25	91.25	74.00	51.50
Share price STL year-end (NOK)	**169.00**	165.25	155.00	95.00	74.75
Market value year-end (NOK billion)	**539**	358	336	206	162
Daily turnover (million shares)	**16.5**	12.6	10.1	6.7	3.3
Ordinary and diluted earnings per share (EPS) (NOK) (1)	**13.80**	15.82	14.19	11.50	7.64
P/E (1) (2)	**12.25**	10.45	10.92	8.26	9.78
Dividend paid per share (NOK) (3)	**8.50**	9.12	8.20	5.30	2.95
Pay-out ratio (4)	**61%**	57%	58%	46%	39%
Dividend yield (5)	**5.0%**	5.5%	5.3%	5.6%	3.9%
Net debt to capital employed (1) (6)	**12.4%**	20.5%	15.1%	18.9%	22.6%
Ordinary shares outstanding, weighted average	**3,195,866,843**	3,230,849,707	2,165,740,054	2,166,142,636	2,166,143,693
Ordinary shares outstanding, year-end	**3,188,647,103**	3,208,800,400	2,189,585,600	2,189,585,600	2,189,585,600

(1) Figures for 2003, 2004 and 2005 are USGAAP, only former Statoil figures.
(2) Share price at year-end divided by EPS.
(3) Proposed dividend for 2007. Including ordinary and special dividend.
(4) Dividend paid per share divided by EPS.
(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



The merger of Norsk Hydro ASA's oil and gas activities with Statoil ASA to form StatoilHydro ASA was completed on 1 October 2007. Following the merger, StatoilHydro ASA had 3,188,647,103 shares 1). StatoilHydro ASA has one class of shares, and each share confers one vote at the general meeting.

StatoilHydro is the biggest company listed on the Oslo stock exchange (Oslo Børs), and it is traded under the ticker code STL. At 31 December 2007, StatoilHydro represented 25% of the total value of all companies registered on Oslo Børs.

The group's share price increased from NOK 165.25 at the end of 2006 to NOK 169.00 at the end of 2007. The Board of Directors proposes an ordinary dividend of NOK 4.20 per share for 2007, as well as NOK 4.30 per share in special dividend for approval by the Annual General Meeting on 20 May 2008. The total dividend of NOK 8.50 per share proposed to be distributed to our shareholders is equivalent to a direct yield of approximately 5.0%, and we will distribute 61% of net income from 2007. Net income per share amounted to NOK 13.80 in 2007, a decrease of 13% compared to 2006.

On average, 16.5 million StatoilHydro shares were traded on the Oslo Børs every day in 2007, an increase of 31% on the previous year. StatoilHydro shares accounted for 21.8% of the total market value traded throughout the year (see the illustration).

At 31 December 2007, StatoilHydro had approximately 97,700 shareholders registered in the Norwegian Central Securities Depository (VPS), an increase corresponding to 43% on the year before. The number of American Depositary Receipts registered on the New York Stock Exchange increased by 70% during the course of the year, from 67.1 million to 113.8 million shares. The increase in the number of shareholders was primarily the result of the merger2).

[1)] One share in Norsk Hydro ASA entitled a shareholder to 0.8622 shares in StatoilHydro ASA.
[2)] According to Hydro's Annual Report, JPMorgan Chase & Co, as depositary of the Hydro ADRs, held interests of 67.7 million ordinary shares in Hydro as of 28 February 2007.

6.1 Dividend policy

Our dividend policy reflects our intention to return to our shareholders, through cash dividends and share repurchases, an amount in the range of 45 to 50% of consolidated net income pursuant to IFRS. It is our ambition to grow the ordinary cash dividend measured in NOK per share. In any one year, however, the aggregate of cash dividends paid to shareholders and share repurchases may be higher or lower than 45 to 50% of net income, depending on StatoilHydro's evaluation of expected cash flow development, capital expenditure plans, financing requirements and appropriate financial flexibility.

Share repurchases are an integrated part of our dividend policy. On 15 May 2007, the annual general meeting of Statoil authorised the board of directors to acquire Statoil shares in the market. The authorisation applies to the acquisition of up to 50 million shares at a price of between NOK 50 and NOK 500 per share. Repurchased shares acquired under this authorisation may only be annulled through a capital reduction. This authorisation is valid until May 2008. StatoilHydro did not make use of this agreement in 2007.

For more information on the purchase of StatoilHydro shares, see report section Purchase of StatoilHydro shares for subsequent cancellation.

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 law, 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 2003 on a per share basis and in the aggregate, as well as cash dividends proposed by our board of directors to be paid in 2008 on our ordinary shares for the fiscal year 2007.

	Per ordinary share[(1)]				Total (in million)	
Year	Ordinary dividend NOK	Special dividend NOK	Total dividend NOK	Total dividend USD	NOK	USD[(2)]
2002	2.90		2.90	0.47	6,282	1,157
2003	2.95		2.95	0.47	6,390	1,177
2004	3.20	2.10	5.30	0.85	11,481	2,114
2005	3.60	4.60	8.20	1.32	17,756	3,269
2006	4.00	5.12	9.12	1.46	19,690	3,625
2007	**4.20**	**4.30**	**8.50**	**1.57**	**27,104**	**4,991**

[(1)] For fiscal years 2007, 2006, 2005, and 2004 the total dividend per share consisted of an ordinary dividend and a special dividend. The 2007 dividend is expected to be paid in end May 2008.
[(2)] The USD amounts in the table above are based on the noon buying rate for NOK on 28 December 2007, which was NOK 5.431 to USD 1.00.

In 2004, 2005 and 2006 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 2007 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.

Since we will only pay dividends in Norwegian kroner, exchange rate fluctuations will affect the U.S. dollar amounts received by holders of ADSs after the ADR depositary converts cash dividends into U.S. dollars.

Share repurchases

Our dividend policy states that share repurchases are an integrated part of shareholder return. Due to the merger between Statoil and Norsk Hydro's oil and gas activities, we did not undertake any share repurchases in 2007 and no shares were acquired in the market for subsequent annulment. In 2006, 20,158,848 shares were repurchased totalling NOK 3.3 billion.

There is no guarantee that share repurchases will continue in the future. 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 Purchase of equity securities by the issuer and affiliated purchasers

6.2.1 StatoilHydro share savings plan

Since 2004, 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 up to 5% of their basic salary in shares. After a lock-in period of two calendar years, one extra share will be awarded for each share purchased. 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 shall take 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 itself decide when shares will be acquired. However, the purchases follow a fixed plan for one year at a time. The authorisation was most recently renewed on 15 May 2007 and it is valid until 1 June 2008.

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.

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 2007	171,500	161.15	1,065,000	2,935,000
February 2007	170,800	162.50	1,235,800	2,764,200
March 2007	187,500	153.31	1,423,300	2,576,700
April 2007	171,000	167.85	1,594,300	2,405,700
May 2007	265,000	162.49	1,859,300	2,140,700
June 2007	251,000	173.30	251,000	5,749,000
July 2007	221,500	193.84	472,500	5,527,500
August 2007	272,500	158.59	745,000	5,255,000
September 2007	239,000	180.24	984,000	5,016,000
October 2007	230,300	184.61	1,214,300	4,785,700
November 2007	247,000	172.07	1,461,300	4,538,700
December 2007	263,000	161.89	1,724,300	4,275,700
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
Total	3,742,100 (2)	164.58 (3)	2,776,300	3,223,700

(1) The authorisation to repurchase a maximum of four million shares with a maximum overall nominal value of NOK 10 million for repurchase of shares in connection with the group’s share investment plan was given by the annual general meeting on 10 May 2006. The authorisation was renewed by the annual general meeting on 15 May 2007 with an increase to a maximum of six million shares with a maximum overall nominal value of 15 million for repurcase of shares, and valid until June 2008.

(2) All shares repurchased have been purchased in the open market and pursuant to the authorisation mentioned above.

(3) Weighted average price per share. Converted for convenience of the reader at the year-end 2007 rate of exchange of USDNOK 5.4310, this is equivalent to USD 30.30.

6.2.2 Purchase of StatoilHydro shares for subsequent cancellation

On 15 May 2007, the annual general meeting of Statoil authorised the board of directors to acquire Statoil shares in the market for subsequent cancellation. The authorisation applies to the acquisition of up to 50 million shares at a price of between NOK 50 and NOK 500 per share. Repurchased shares acquired under this authorisation may only be annulled through a capital reduction. This authorisation is valid until 20 May 2008. StatoilHydro did not make use of this authorisation in 2007.

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 annulment 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 annulled.

6.3 Information and communications

We place great emphasis on keeping the stock market and the world at large informed about developments in the company's financial performance and future prospects. Information provided to the stock market must be characterised by transparency and 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 all price-sensitive information to Oslo Børs and the US Securities and Exchange Commission.

Our registrar manages our shares listed on the Oslo stock exchange on our behalf and provides the connection to the Norwegian Central Securities Depository (VPS). Major services provided by the registrar are investor services for private shareholders, the disbursement of dividend and assistance at our general meetings. DnB NOR 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 are broadcast 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.

6.3.2 Ticker codes

Oslo Børs STL
New York Stock Exchange STO
Reuters STL.OL
Bloomberg STL NO

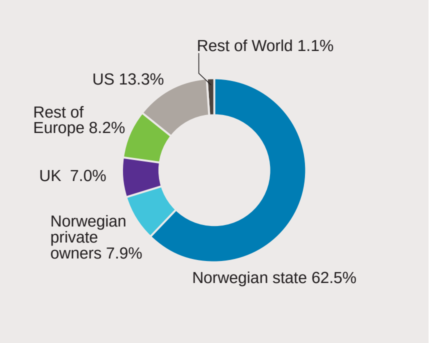
6.4 Major shareholders

The Norwegian State is the largest shareholder in StatoilHydro. Its ownership interest is managed by the Ministry of Petroleum and Energy.

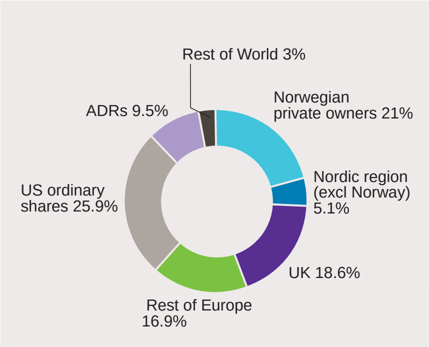
Statoil was partially privatised and listed on the stock exchange on 18 June 2001, when it became a public limited company. After the initial offering, the government retained 81.7% of the Statoil shares. In July 2004, the Norwegian Ministry of Petroleum reduced its ownership in Statoil to 75.47% through a sale to institutional and other investors. On 16 February 2005 the Norwegian Ministry of Petroleum and Energy sold 100 million Statoil shares through an off-exchange underwritten block sale. This represented 4.6% of our shares at that time. The shares were sold to a global investment bank and were passed on to institutional investors in Norway and abroad. In addition, 17.65 million shares were made available for sale to private investors, at the rate set in the institutional sale.

Following these transactions, the Norwegian state owned 70.9% of the shares of Statoil prior to the merger with Hydro's oil and gas activities.

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 is currently 62.5%, or 1,992,959,739 shares. In accordance with the Storting's decision of 2001 concerning a minimum state shareholding of two-thirds in Statoil, the Government has expressed its intention to increase the state's shareholding in StatoilHydro over time to 67%.

As of 31 December 2007, the National Insurance Fund, (Folketrygdfondet) owned 75,112,119 shares, or 2.4% 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 25 March 2008.

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 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 that in the United States, as of 25 March 2008, there were 129,284,456 ADRs outstanding (representing approximately 4.05 % of the ordinary shares outstanding). As of 25 March 2008 there were 609 registered holders of ADRs resident in the United States. Furthermore, as of 25 March 2008, 425,148,243 regular shares were held by 456 registered holders resident in the United States.

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.

If the Norwegian State, acting through the Minister of Petroleum and Energy, increases its holding in excess of two-thirds of the shares in the company, it would have 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 31 December	Type	Number of shares	Ownership interest
The Norwegian State (Ministry of Petroleum and Energy		1,992,959,739	62.50%
Bank of New York, ADR department	Nominee	113,822,751	3.57%
State Street Bank	Nominee	105,703,220	3.31%
Folketrygdfondet (Norwegian national insurance fund)		75,112,119	2.36%
JP Morgan Chase Bank	Nominee	56,756,683	1.78%
Clearstream Banking	Nominee	31,805,904	1.00%
The Northern Trust	Nominee	29,318,375	0.92%
Mellon Bank	Nominee	28,336,711	0.89%
Mellon Bank	Nominee	18,227,541	0.57%
Vital Forsikring ASA		18,023,513	0.57%
JP Morgan Chase Bank	Nominee	17,839,634	0.56%
State Street Bank	Nominee	16,267,561	0.51%
The Northern Trust	Nominee	12,362,347	0.39%
Investors Bank	Nominee	11,967,612	0.38%
Investors Bank	Nominee	11,816,247	0.37%
Svenska Handelsbank	Nominee	11,313,411	0.35%
Fidlity Funds Europe		10,934,861	0.34%
State Street Bank	Nominee	10,472,727	0.33%
DnB Nor Norge		9,961,835	0.31%
RBC Dexia Investors	Nominee	9,389,955	0.29%

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 (Oslo Børs) 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				
2003	74.75	51.50	11.30	7.29
2004	103.50	74.00	15.93	10.85
2005	166.50	91.25	25.80	14.69
2006	210.50	147.25	34.52	22.39
2007	191.50	151.50	35.19	23.90
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
March up until 25 March 2008	169.90	135.30	31.73	24.44
Month of				
September 2007	191.50	167.75	34.93	29.65
October 2007	187.00	169.75	35.19	31.47
November 2007	183.50	166.00	34.42	29.96
December 2007	185.00	159.90	33.84	28.77
January 2008	169.90	135.30	31.73	24.44
February 2008	162.40	141.50	31.31	25.86
March up until 25 March 2008	159.90	149.00	30.85	27.97

6.6 Taxation

Norwegian tax matters
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. 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.

On 10 December 2004 the Norwegian tax reform was approved by the Storting. The reform entered into force with effect from 2006.

Taxation of dividends
Corporate shareholders resident in Norway for tax purposes are exempt from tax on dividends distributed by Norwegian companies. 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 genuinely resident for tax purposes in a country in the European Economic Agreement area (EEA area) provided that the corporate shareholder is involved in genuine economic business activity in that country. 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. However, the treaty is currently being renegotiated. Current signals indicate that a new treaty may come into effect from 2009. 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

Corporate shareholders resident in Norway for tax purposes are exempt from tax on gains on the disposal of shares. 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 Statoil 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 affecting shareholders

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 for 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.

	For the year ended 31 December			
Year	**Low**	**High**	**Average**	**End of period**
2003	6.6440	7.6560	7.0627	6.6660
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**

USDNOK exchange rates	Low	High
2007		
September	5.4095	5.8154
October	5.3487	5.4738
November	5.2619	5.5255
December	5.4047	5.5944
2008		
January	5.2637	5.5487
February	5.1898	5.5546
March (up to and including 25 March)	5.1066	5.2780

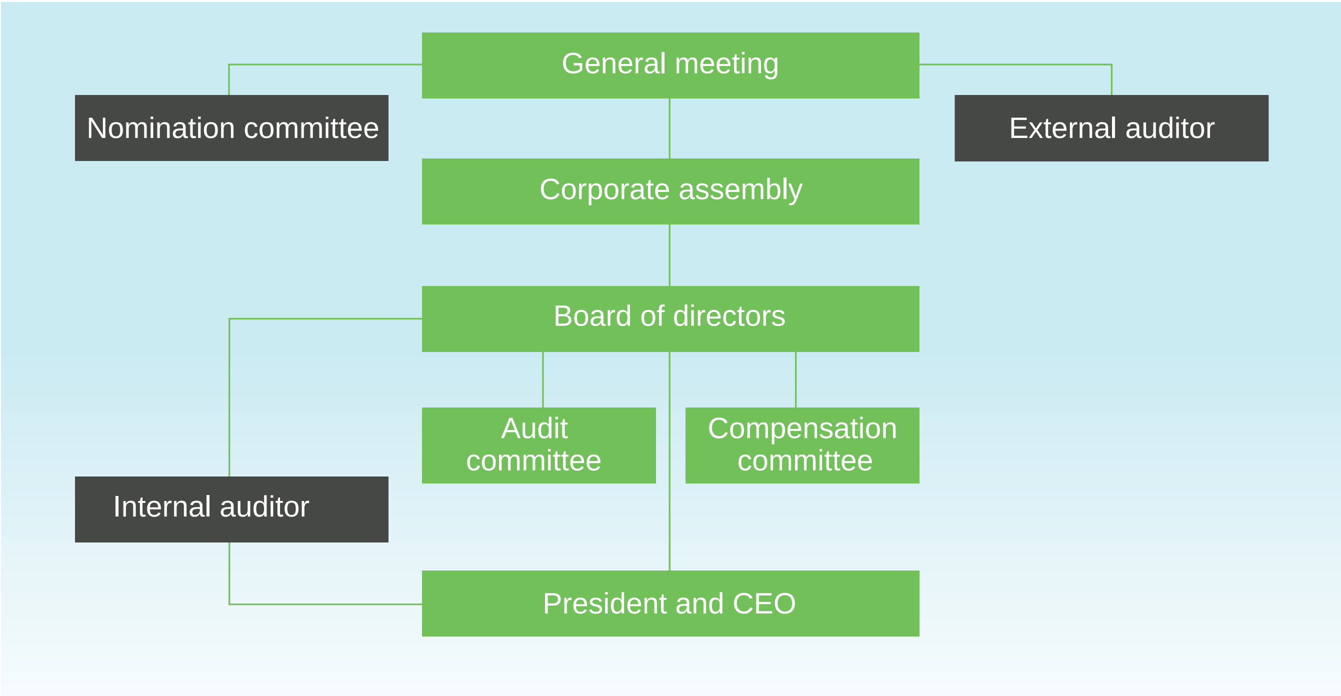
On 25 March 2008 the noon buying rate for Norwegian kroner was USD 1.00 = 5.1824 NOK.

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

Good corporate governance is a prerequisite for a sound and sustainable company. It must build on openness and equal treatment of all shareholders. Our governing structures and controls help to ensure that we run our business in a justifiable and profitable manner to the benefit of our employees, shareholders, partners, customers and society.

StatoilHydro is a public limited company with a governance structure based on Norwegian law. StatoilHydro's main share listing is on the Oslo stock exchange (Oslo Børs). It is also listed on the New York Stock Exchange.



StatoilHydro's board of directors endorses the "Norwegian Code of Practice for Corporate Governance" (updated on 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. A complete report on corporate governance in StatoilHydro, sequenced as the Norwegian code of practice stipulates, is found on these web pages:http://www.statoilhydro.com/en/aboutstatoilhydro/corporategovernance/norwegiancodeofpractice/pages/default.aspx

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 found on our website http://www.statoilhydro.com/en/aboutstatoilhydro/corporategovernance/norwegiancodeofpractice/pages/statementofdifference.aspx

7.1 Ethics Code of Conduct

Our ability to create value is dependent on high ethical standards. Ethics is treated as an integral part of our business activities, and we act within the law and comfortably within our own ethical principles. The group requires high ethical standards of everyone who acts on its behalf and it will maintain an open dialogue on ethical issues, internally and externally. The StatoilHydro Ethics Code of Conduct describes the requirements that apply to StatoilHydro's business practices. The Code's target group is all employees and members of the board of directors of StatoilHydro and its subsidiaries. The Ethics Code of Conduct is accessible at our website at www.statoilhydro.com/en/AboutStatoilHydro/EthicsValues/Pages.

Together with StatoilHydro's values statement, the Ethics Code of Conduct constitutes the basis and framework for the performance culture StatoilHydro intends to develop.

Business partners are also expected to have ethical standards that are compatible with StatoilHydro's standards.

7.2 Articles of association for StatoilHydro ASA

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 our website.

7.3 General meeting of Shareholders

The annual general meeting of shareholders (AGM) is the company's supreme body. 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 will introduce 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.

In 2007, an extraordinary general meeting on 5 July was convened by the board of directors to obtain the shareholders' approval of the plan to merge Statoil and Norsk Hydro's oil and gas activities.

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 members service contracts that provide for benefits upon termination of office.

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.

Board developments in 2007

The board held 25 meetings in 2007. Attendance at board meetings was 93%.

Up until 30 September 2007, the board of directors of Statoil ASA consisted of Jannik Lindbæk (chair), Kaci Kullman Five (deputy chair), Finn A. Hvistendahl, Grace Reksten Skaugen, Knut Åm, Ingrid Wiik, Marit Arnstad, Lill-Heidi Bakkerud, Claus Clausen and Morten Svaan. Following the merger of Statoil with Norsk Hydro ASA's oil and gas activities on 1 October 2007, the board of directors of StatoilHydro ASA consisted of the President and CEO of Norsk Hydro ASA Eivind Reiten (chair), Marit Arnstad (deputy chair), Kjell Bjørndalen, Roy Franklin, Elisabeth Grieg, Grace Reksten Skaugen, Kurt Anker Nielsen, Lill-Heidi Bakkerud, Claus Clausen and Morten Svaan. Geir Nilsen and Ragnar Fritsvold are employee-elected observers. On 4 October 2007, Eivind Reiten decided to resign as chair of the board and from that date Marit Arnstad was acting chair until 1 April 2008.

On 30 January 2008, the corporate assembly elected Svein Rennemo (60) as new chair of the board with effect from 1 April 2008, in accordance with the nomination committee's recommendation.

Svein Rennemo.

Svein Rennemo (born 1947). Chair of the board since 1 April 2008. Svein Rennemo is a Norwegian citizen and he lives in Norway. Economist from the University of Oslo. During the period 1972 -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. He has held various management positions in Statoil from 1982 to 1994, latterly as head of the petrochemical division. Mr Rennemo worked for Borealis from 1994 to 2001, first as deputy CEO and CFO and from 1997 as CEO. Today, Mr Rennemo is chair of the board of Integrated Optoelectronics AS. He has also been CEO of Petroleum Geo Services AS since 2002, a position he left on 1 April 2008. Mr. Rennemo has no loans in the company.

Marit Arnstad.

Marit Arnstad (born 1962). Deputy chair. Ms Arnstad is a Norwegian citizen and she lives in Norway. She graduated in law at the University of Oslo. Ms Arnstad was Minister of Petroleum and Energy from 1997 to 2000. Member of the Storting for the Centre Party during the periods 1993 to 1997 and 2001 to 2005. Head of the party's parliamentary group from 2003 to 2005. Higher Executive Officer of the Ministry of the Environment, assistant advocate with the law firm Advokatfirmaet Wiersholm, Mellbye og Bech. Advisor with the law firm Advokatfirmaet Schjødt. Chair of the board of directors of the Norwegian University of Science and Technology (NTNU) and member of the boards of Adresseavisen ASA, NTE Nett AS, Aker Seafood ASA and Acta ASA. Ms Arnstad was a member of the board of Statoil from June 2006 and became acting chair of StatoilHydro on 4 October 2007. She has no loans in the company and is a member of the board's audit committee.

Kjell Bjørndalen.

Kjell Bjørndalen (born 1946). Board member. Kjell Bjørndalen is a Norwegian citizen and he lives in Norway. 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) until October 2007. He is a member of the boards of ABN AMRO Kapitalforvaltning AS and Bank 1 Oslo. Kjell Bjørndalen has no loans in the company. He has been a member of the board of StatoilHydro and of the board's compensation committee since 1 October 2007.

Roy Franklin.

Roy Franklin (born 1953). Board member. Roy Franklin is a UK citizen and he lives in the UK. Bachelor of Science in geology from the University of Southampton in the UK. Has broad experience from management positions in several countries, including positions with BP, Paladin Resources plc and Clyde Petroleum plc. He was head 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 chair of the boards of Bateman Litwin NV, Novera Energy Ltd, a leading British company in the field of renewable energy, and Keller Group plc, a London-based international engineering company. Board member of the Australian oil and gas company Santos Ltd. In 2004, he was awarded an OBE for his work for the British oil and gas industry. Mr Franklin has no loans in the company. He has been a member of the board of StatoilHydro and of the board's audit committee since 1 October 2007.

Elisabeth Grieg.

Elisabeth Grieg (born 1959). Board member. Elisabeth Grieg is a Norwegian citizen and she lives in Norway. Chair of the board of Grieg Shipping Group, co-owner of the Grieg Group and chief executive of Grieg International AS. President of the Norwegian Shipowners' Association and member of the boards of Star Shipping AS, Grieg International AS, Grieg Maturitas AS, Grieg Foundation and SOS Children's Villages in Norway. Member of the corporate assembly and election committee of Orkla ASA, and of the Council of Det Norske Veritas. A member of the board of Norsk Hydro ASA from 2001 to 2007, she became a member of the board of StatoilHydro from 1 October 2007. Elisabeth Grieg partly owns the family company Grieg Maturitas AS, which indirectly holds 20% of the ownership of AON Grieg. AON Grieg acted as a broker for Norsk Hydro and for Statoil in 2007 and in total received NOK 17,676,216 in fees from Norsk Hydro and Statoil in 2007. Her husband, Stig Grimsgaard Andersen, was a board member in AON Grieg in 2007. In addition, Grieg Maturitas AS and other family companies hold indirectly and directly 75% of the ownership of Grieg Logistics. Her husband, Stig Grimsgaard Andersen, is a board member in Grieg Logistics. Grieg Logistics has provided logistics/transportation services to Statoil, to Hydro's oil and gas activities and to StatoilHydro in 2007 and has received in total fees of NOK 102,159,731. Ms Grieg has no loans in the company. Ms Grieg is a member of the board's compensation committee.

Kurt Anker Nielsen.

Kurt Anker Nielsen (born 1945). Board member. Kurt Anker Nielsen is a Danish citizen and he lives in Denmark. Has held management positions in Novo A/S and Novo Nordisk A/S, including the positions of CFO and managing director. Deputy chair of the board of Novozymes A/S and a member of the boards of Novo Nordisk A/S, Novo Nordisk Fonden, ZymoGenetics Inc, Vestas Wind Systems A/S and Life Cycle Pharma A/S. Mr Nielsen is the chair of the boards of Reliance A/S and Collstrups Mindelegat. Member of the board of Norsk Hydro ASA from 2004 to 2007, became a member of the board of StatoilHydro from 1 October 2007. Mr Nielsen has no loans in the company. He is chair of the board's audit committee.

Grace Reksten Skaugen.

Grace Reksten Skaugen (born 1953). Board member. Grace Reksten Skaugen is a Norwegian citizen and she lives in Norway. 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). Self-employed consultant, head of 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. Chair of the boards of Entra Eiendom AS and Ferd Holding, member of the boards of the Swedish listed companies Investor AB and Atlas Copco AB. Member of the board of Statoil from 2002 and a member of the board of StatoilHydro from 1 October 2007. Grace Reksten Skaugen has no loans in the company. Ms Skaugen is a member of the board's compensation committee.

Lill-Heidi Bakkerud.

Lill-Heidi Bakkerud (born 1963). Board member. Lill-Heidi Bakkerud is a Norwegian citizen and she lives in Norway. Represents the employees in the board, and is a full-time employee representative as head of the trade union Industry Energy (IE). A qualified process/chemistry worker, she has worked as a process technician at the petrochemical plant in Bamble and on the Gullfaks field in the North Sea. She is a member of IE's executive committee and holds a number of offices as a result of this. Elected by the employees as member of the board of Statoil from 2004. She was also a board member during the period 1998 to 2002. Has been a member of StatoilHydro's board from 1 October 2007. Lill-Heidi Bakkerud has no loans in the company.

Claus Clausen.

Claus Clausen (born 1954). Board member. Claus Clausen is a Norwegian citizen and he lives in Norway. An employee representative. Mr Clausen graduated as an engineer from Bergen College of Engineering. Worked for Statoil since 1991. Has held various positions in the process discipline since 1997. Today, he is discipline manager for process in operational technology on the Statfjord field. Deputy leader of the Nito branch in Stavanger. Member of the works council for the Exploration & Production Norway business area in StatoilHydro. Elected by the employees as a member of the board of Statoil from 2006, board member of StatoilHydro from 1 October 2007. Claus Clausen has no loans in the company.

Morten Svaan.

Morten Svaan (born 1956). Board member. Morten Svaan is a Norwegian citizen and he lives in Norway. Represents the employees on the board, and was chief employee representative for Nifo/Tekna from 2000 to 2004. He has a PhD in chemistry from the Norwegian University of Science and Technology and studied business economics at the Norwegian School of Management (BI). Has worked for Statoil since 1985. He is presently working on health, safety and the environment (HSE) for the Technology & New Energy business area, focusing on safety and emergency response. Mr Svaan has an employee loan in the company on the terms and conditions that apply to all employees at his employment level. As of 31 December 2007, the amount of the loan was NOK 61,000. Member of the board of Statoil from June 2004, and of StatoilHydro from 1 October 2007. Mr Svaan is also a member of the board's audit committee.

Ragnar Fritsvold.

Ragnar Fritsvold (born 1948). Observer. Ragnar Fritsvold is a Norwegian citizen and he lives in Norway. An employee-elected observer on the board of StatoilHydro since 1 October 2007. Elected as employee representative to the board of Norsk Hydro ASA in May 2007. He 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 Chartered Scientific and Academic Professionals Norway (Tekna) from 1999 to 2007.

Geir Nilsen.

Geir Nilsen (born 1955). Observer. Geir Nilsen is a Norwegian citizen and he lives in Norway. Employee-elected observer on the board of StatoilHydro since 1 October 2007. Employed as maintenance manager, he represents employees who are members of the Norwegian Confederation of Trade Unions (LO). Mr Nilsen was elected to the board of Hydro by the employees, and was a board member from 2003 to 2007.

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 and risk audit function, (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 seven meetings in 2007. There was 99% 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, Mr 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 Mr Nielsen is independent under the meaning of Rule 10A-3 under the Securities Exchange Act.

7.4.1.2 Exemptions from the listing standards for audit committees

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 companies 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 in connection with (1) the further development of StatoilHydro's rewards philosophy and strategy in general, and, more specifically, with respect to compensation of the CEO, (2) devising internally consistent and externally competitive overall compensation programmes in order to attract, retain and reward the CEO and key executives for their performance in relation to the achievement of financial goals, values and leadership approach, and (3) by providing guidance, direction and monitoring of StatoilHydro's compensation programmes seen in relation to the long-term interests of the shareholders.

The committee comprises three board members. At year end 2007, the committee members were Grace Reksten Skaugen (acting chair), Elisabeth Grieg and Kjell Bjørndalen.

The committee held 8 meetings in 2007. There was 100 % 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

The corporate assembly's duties include supervising the board of directors and the president and CEO in their management of the company. On the basis of proposals from the board of directors, the corporate assembly makes decisions on matters involving substantial investments measured in relation to the total resources of the company, and on matters regarding the rationalisation or restructuring of operations that will result in a major change in the workforce. The corporate assembly is responsible for electing the board of directors.

The corporate assembly held four meetings in 2007.

The following is a list of the members of the corporate assembly as of 31 December 2007:

Name	Place of Residence	Age	Position
Olaug Svarva	Oslo, Norway	50	Chair, Shareholder elected
Idar Kreutzer	Oslo, Norway	45	Deputy chair, Shareholder elected
Erlend Grimstad	Oslo, Norway	40	Shareholder elected
Greger Mannsverk	Kirkenes, Norway	46	Shareholder elected
Steinar Olsen	Stavanger, Norway	58	Shareholder elected
Benedicte Berg Schilbred	Tromsø, Norway	61	Shareholder elected
Ingvald Strømmen	Ranheim, Norway	57	Shareholder elected
Inger Østensjø	Stavanger, Norway	54	Shareholder elected
Rune Bjerke	Oslo, Norway	47	Shareholder elected
Gro Brækken	Snarøya, Oslo	55	Shareholder elected
Benedicte Schilbred Fasmer	Godvik, Norway	42	Shareholder elected
Kåre Rommetveit	Hjellestad, Bergen	62	Shareholder elected
Anne Synnøve Hebnes	Stavanger, Norway	35	Employee representative
Per Helge Ødegård	Porsgrunn, Norway	45	Employee representative
Arvid Færaas	Vormedal, Norway	45	Employee representative
Einar Arne Iversen	Molde, Norway	45	Employee representative
Tore Amund Fredriksen	Porsgrunn, Norway	54	Employee representative
Per Martin Labråthen	Brevik, Norway	46	Employee representative
Stein Bredal	Finnøy, Norway	57	Employee representative, observer
Anne K.S. Horneland	Hafrsfjord, Norway	51	Employee representative, observer

7.6 Management

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.

Helge Lund. Chief executive officer

Helge Lund, (born 1962). Chief Executive Officer (CEO). President and CEO of StatoilHydro since 1 October 2007. President and CEO of Statoil since 2004. MA in business economics from the Norwegian School of Economics and Business Administration in Bergen and Master of Business Administration (MBA) from INSEAD in France. Came to Statoil from the position of CEO in Aker Kværner ASA. Held central management positions in the Aker RGI system from 1999. Has been political advisor to the parliamentary group of the Norwegian conservative party, a consultant with McKinsey & Co and Deputy Managing Director of Nycomed Pharma AS. No external offices.

Eldar Sætre. Chief financial officer

Eldar Sætre (born 1956). Chief Financial Officer (CFO). CFO of StatoilHydro since 1 October 2007. CFO of Statoil from October 2003. MA in business economics from the Norwegian School of Economics and Business Administration in Bergen. Has worked for Statoil since 1980. Has held several management positions in the group in the fields of accounting and finance. Member of the board of directors of Strømberg Gruppen AS.

Tore Torvund. Executive vice president, Exploration & Production Norway

Tore Torvund (born 1952). Executive vice president, Exploration & Production Norway. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Hydro's Oil and Energy division from February 2000. MA in engineering (petroleum technology) from the Norwegian Institute of Technology (NTH) in Trondheim. Responsible for Hydro's exploration and operations activities on the Norwegian continental shelf from 1990 to 2000. Various management positions in Hydro's exploration and production division in connection with the development of fields in the North Sea. Employed by the French oil company Elf Aquitaine 1977 - 1982, working in Stavanger and Paris.

Peter Mellbye. Executive vice president, International Exploration & Production

Peter Mellbye (born 1949). Executive vice president, International Exploration & Production. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Statoil from March 1992. Cand. polit. degree from the University of Oslo. Has worked for Statoil since 1982 and has held central management positions. Executive vice president of Natural Gas from 1992 to 2004. Worked for the Ministry of Trade and the Norwegian Trade Council before joining Statoil. Member of the board of directors of the Energy Policy Foundation of Norway (EPF).

Rune Bjørnson. Executive vice president, Natural Gas

Rune Bjørnson (born 1959). Executive vice president, Natural Gas. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Statoil from 2004. Cand. polit. degree from the University of Bergen. Has worked for Statoil from 1985. Has held various management positions in the Natural Gas business area and was vice president in Statoil UK from 2001 to 2003. No external offices.

Jon Arnt Jacobsen. Executive vice president, Manufacturing & Marketing

Jon Arnt Jacobsen (born 1957), Executive vice president, Manufacturing & Marketing. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Statoil from September 2004. MA in business economics from the Norwegian School of Management (BI) in Oslo and Master of Business Administration(MBA) from the University of Wisconsin. Senior Vice president Group Finance in Statoil from 1998 to 2004. Earlier employment includes 13 years in Den norske Bank including General Manager and Head of DnB's Singapore branch. No external offices.

Margareth Øvrum. Executive vice president, Technology & New Energy

Margareth Øvrum (born 1958). Executive vice president, Technology & New Energy. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Statoil from September 2004. MA in engineering from the Norwegian Institute of Technology (NTH) in Trondheim, specialising in technical physics. Has worked for Statoil since 1982. Has held central management positions in Statoil, including 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. Has been vice president for operations for Veslefrikk and vice president of operations support for the Norwegian continental shelf. Member of the board of directors of Elkem and of the supervisory board of Storebrand ASA.

Morten Ruud. Executive vice president, Projects

Morten Ruud (born 1952). Executive vice president, Projects. Executive vice president in StatoilHydro since 1 October 2007. Vice president in Hydro's Oil and Energy division from 1993 and senior vice president for Projects in Hydro from 1 January 2004. MA in engineering from the Norwegian Institute of Technology (NTH) in Trondheim and also has a Master's degree in Mechanical Engineering. Held leading positions in the Oseberg project from 1982 to 1989, head of the Brage project from 1989 to 1992 and the Troll Oil project from 1992 to1996. Responsible for Operations on the Norwegian continental shelf from 1996 to 1997 and International Exploration and Production from 1997 to 2004.

Hilde Merete Aasheim. Executive vice president, staffs and corporate services

Hilde Merete Aasheim (born 1958). Executive vice president, Staff functions and corporate services. Executive vice president in StatoilHydro since 1 October 2007. Executive vice president in Hydro from 2005. MA in business economics from the Norwegian School of Economics and Business Administration in Bergen and a state authorised public accountant. Worked for Hydro from October 2005. Responsible for the staff area, which comprise people and organisation , communication, health, safety and the environment, integrity and social responsibility, information management and technology, management systems and global business services. Held key management positions in Elkem from 1986 to 2005. Member of corporate executive committee in Elkem for a number of years . Board member in Veidekke ASA.

7.7 Nomination committee

StatoilHydro's nomination committee (referred to as the election committee in the articles of association) is elected by the general meeting of shareholders in accordance with the articles of association. 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 regarding the election of shareholder-elected members to the corporate assembly
- to present recommendations to the corporate assembly regarding 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.

Members of the nomination committee are elected for a term of two years. The nomination committee held 28 meetings in 2007.

The members of the nomination committee are:
Olaug Svarva (chair). Managing Director, Folketrygdfondet
Benedicte Schilbred Fasmer, Divisional Director, Sparebanken Vest
Tom Rathke, Managing Director, Vital Forsikring and Executive Vice President, DnB NOR
Bjørn Ståle Haavik, Director General, Ministry of Petroleum and Energy

The rules of procedure for the nomination committee and a form for proposing candidates are accessible on http://www.statoilhydro.com/en/AboutStatoilHydro/CorporateGovernance/GoverningBodies/ElectionCommittee/Pages/default.aspx.

7.8 Independent registered public accounting firm

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 2007

Ernst & Young AS is the company's independent registered public accounting firm, whereas Deloitte audited Norsk Hydro's oil and gas business for 2006. The table below itemises the expensed remuneration to the external auditor in 2007 and 2006, respectively:

(in NOK million)	Audit fee	Audit related fee	Total
2007			
Ernst & Young - Norway	18.6	7.4	26.0
Ernst & Young - outside Norway	26.2	1.1	27.3
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

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 for 2006 audit fee and other fees to Deloitte amounting to NOK 39.4 and NOK 5.6 million for 2007 and 2006, respectively and audit fees to Ernst & Young related to StatoilHydro-operated licenses amounting to NOK 6.1 and NOK 4.0 million for 2007 and 2006, respectively.

There were no other fees paid to Ernst & Young.

The change in audit fee and audit related fee from 2006 to 2007 are mainly due to increase in activity in connection with the merger with Norsk Hydro's oil and gas assets.

7.9 Compensation to the governing bodies

Compensation paid to the board of directors, corporate executive committee, nomination committee and corporate assembly
In 2007, remuneration totalling NOK 580,000 was paid to the members of the corporate assembly, NOK 3,255,344 to the members of the board of directors, NOK 348,000 to the members of the nomination committee and NOK 63,064,000 to the members of the corporate executive committee.

Detailed information about the remuneration of members of the board of directors paid out through the year 2007 and the members of the corporate executive committee as per 31 December 2007 is given in the tables below.

Members of the board (in thousand NOK)	Board remuneration	Audit Committee	Compensation Committee	Total Remuneration
Åm Knut	169	25	70	264
Svaan Morten	239	50		289
Fritsvold Ragnar Per	70			70
Bakkerud Lill Heidi	239			239
Nilsen Geir	70			70
Skaugen Grace R.	239		80	319
Five Kaci Kullmann	210			210
Lindbæk Jannik	338		70	408
Grieg Elisabeth	70		7	77
Nielsen Kurt Anker	70	38		108
Franklin Roy	124	25		149
Wiik Ingrid	169	25		194
Reiten Eivind	8			8
Arnstad Marit	305	25		330
Clausen Claus	239			239
Bjørndalen Kjell	70		7	77
Hvistendahl Finn A.	169	38		206
Total	2,796	225	234	3,255

Members of Corporate Executive Committee	Fixed salary	Bonus	Benefits in kind	Taxable reimbur-sements	Taxable salary	Benefits in kind	Reimbur-sements	Non taxable salary	Total Remun.	Pension cost	Present value of pension obligations
Lund Helge	5,214	2,491	286	8	7,999	312	12	324	8,323	4,070	13,759
Bjørnson Rune	2,321	844	197	17	3,378	0	20	20	3,398	816	17,349
Jacobsen Jon Arnt	2,703	978	59	131	3,872	0	17	17	3,889	1,503	13,669
Mellby Peter	3,218	1,074	162	32	4,486	0	38	38	4,525	1,525	37,528
Ruud Morten (1)	595	0	3	34	632	0	10	10	641	683	17,896
Sætre Eldar	2,775	1,154	190	8	4,127	25	20	44	4,171	937	24,454
Torvund Tore (1)	938	0	3	33	973	0	48	48	1,022	1,175	34,600
Øvrum Margareth	2,887	1,035	121	135	4,177	171	29	200	4,377	895	22,169
Aasheim Hilde Merete (1)	699	0	39	0	739	42	18	60	799	1,160	2,489
Total	21,350	7,576	1,060	398	30,383	549	211	761	31,144	12,764	183,912

(1) Remuneration from StatoilHydro.
Pension cost consist of benefits earned during the year.

Bonuses received in 2007 include bonuses for all of 2006 and the first nine months of 2007. Potential bonuses for the remaining three months of 2007 will be combined with bonuses for 2008, if any, and paid in 2009.

Among the members of the corporate executive committee, some have received remuneration in the period up to 30 September 2007 pursuant to the policies that governed Norsk Hydro's oil and gas Business up until that point in time. The amounts received under such policies are not necessarily representative of current policies and therefore of future compensation.

Corporate Executive Remuneration earned in Norsk Hydro ASA	Fixed salary	Bonus	Share appreciation rights (1)	Benefits in kind	Taxable reimbur-sements	Taxable salary	Benefits in kind	Reimbur-sements	Non taxable salary	Total Remun.
Ruud Morten	1,696	642	6,084	126	10	8,558	0	13	13	8,571
Torvund Tore	2,688	690	14,255	172	3	17,808	9	187	195	18,004
Aasheim Hilde Merete	1,559	684	3,200	107	4	5,553	0	12	12	5,565
Total	5,943	2,016	23,539	404	17	31,920	9	212	221	32,140

(1) Includes exercised and terminated

7.10 Share ownership

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 of them owns less than 1% of the StatoilHydro shares outstanding.

Ownership of StatoilHydro shares (including share ownership of "close associates")	Pr 31 December 2007	Pr 25 March 2008
Members of the Corporate Executive Committee		
Helge Lund	5980	6761
Eldar Sætre	2639	2883
Margareth Øvrum	4284	4581
Rune Bjørnson	1347	1479
Jon Arnt Jacobsen	3821	4065
Peter Mellbye	4401	4401
Tore Torvund	33368	33431
Morten Ruud	5087	5087
Hilde Aasheim	117	117
Members of the Board of Directors		
Svein Rennemo		0 (1)
Marit Arnstad	0	0
Elisabeth Grieg	33108	33108
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	633	662
Ragnar Fritsvold (2)	259	259
Geir Nilsen (2)	453	453

(1) Entered the Board as Chair on 1 April 2008

(2) Observer

Members of the Corporate Assembly owned as of 31 December 2007 a total of 3529 shares and as of 25 March 2008 a total of 3884 shares.

7.11 Controls and procedures

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

Management excluded from its assessment internal control over financial reporting of Norsk Hydro's oil and gas operations (consolidated subsidiaries), which merged with Statoil ASA with effect from 1 October 2007, and whose financial statements reflect total assets and revenues that account for 24% and 14%, respectively, of the related amounts in the consolidated financial statement as of and for the year ended 31 December 2007. Additional revenues from Norsk Hydro oil and gas operations in 2007 representing 5% of total consolidated revenues have already been integrated in StatoilHydro sales processes.

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 2007 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 2007 have 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 financial statements section 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 2007	2006
REVENUES AND OTHER INCOME			
Revenues		**521,665**	518,960
Net income (loss) from equity accounted investments		**609**	679
Other income		**523**	1,843
Total revenues and other income	5	**522,797**	521,482
OPERATING EXPENSES			
Cost of goods sold		**(260,396)**	(249,593)
Operating expenses		**(60,318)**	(44,801)
Selling, general and administrative expenses		**(14,174)**	(10,824)
Depreciation, amortisation and impairment losses		**(39,372)**	(39,450)
Exploration expenses		**(11,333)**	(10,650)
Total operating expenses		**(385,593)**	(355,318)
Net operating income	5	**137,204**	166,164
FINANCIAL ITEMS			
Net foreign exchange gains (losses)		**10,043**	4,457
Interest income and other financial items		**2,305**	3,675
Interest and other finance expenses		**(2,741)**	(3,060)
Net financial items	8	**9,607**	5,072
Income before tax		**146,811**	171,236
Income tax	9	**(102,170)**	(119,389)
Net income		**44,641**	51,847
Attributable to:			
Equity holders of the parent company		**44,096**	51,117
Minority interest		**545**	730
		44,641	51,847
Earnings per share for income attributable to equity holders of the company - basic and diluted	10	**13.80**	15.82

CONSOLIDATED BALANCE SHEETS

(in NOK million)	Note	At 31 December 2007	At 31 December 2006
ASSETS			
Non-current assets			
Property, plant and equipment	11	**278,352**	272,163
Intangible assets	12	**44,850**	31,205
Equity accounted investments	13	**8,421**	8,556
Deferred tax assets	9	**793**	808
Pension assets	21	**1,622**	1,113
Financial investments	14	**15,266**	14,012
Derivative financial instruments	28	**609**	450
Financial receivables	14	**3,515**	4,341
Total non-current assets		**353,428**	332,648
Current assets			
Inventories	15	**17,696**	15,256
Trade and other receivables	16	**69,378**	62,359
Norsk Hydro ASA merger receivable	3	**0**	18,687
Derivative financial instruments	28	**21,093**	21,323
Financial investments	17	**3,359**	1,032
Cash and cash equivalents	18	**18,264**	7,518
Total current assets		**129,790**	126,175
TOTAL ASSETS		**483,218**	458,823

CONSOLIDATED BALANCE SHEETS

(in NOK million)	Note	At 31 December 2007	At 31 December 2006
EQUITY AND LIABILITIES			
Equity			
Share capital		**7,972**	8,022
Treasury shares		**(6)**	(54)
Additional paid-in capital		**41,370**	44,684
Additional paid-in capital related to treasury shares		**(359)**	(3,605)
Retained earnings		**140,909**	122,153
Other reserves		**(12,611)**	(3,367)
StatoilHydro shareholders' equity		**177,275**	167,833
Minority interest		**1,792**	1,574
Total equity	19	**179,067**	169,407
Non-current liabilities			
Financial liabilities	20	**44,373**	49,215
Deferred tax liabilities	9	**67,477**	72,084
Pension liabilities	21	**19,092**	11,028
Other provisions	22	**43,845**	42,173
Derivative financial instruments	28	**1**	66
Total non-current liabilities		**174,788**	174,566
Current liabilities			
Trade and other payables	23	**64,624**	55,595
Income taxes payable	9	**50,941**	47,149
Financial liabilities	20	**6,166**	5,557
Derivative financial instruments	28	**7,632**	6,549
Total current liabilities		**129,363**	114,850
Total liabilities		**304,151**	289,416
TOTAL EQUITY AND LIABILITIES		**483,218**	458,823

CONSOLIDATED STATEMENTS OF RECOGNISED INCOME AND EXPENSE

(in NOK million)	For the year ended 31 December 2007	2006
Foreign currency translation differences	**(9,858)**	(3,817)
Actuarial gains (losses) on employee retirement benefit plans	**74**	(3,032)
Change in fair value of available for sale financial assets	**1,039**	(524)
Change in fair value of available for sale financial assets transferred to the Consolidated Statements of Income	**(113)**	0
Income tax on income and expense recognised directly in equity	**(175)**	2,321
Income and expense recognised directly in equity	**(9,033)**	(5,052)
Net income for the period	**44,641**	51,847
Total recognised income and expense for the period	**35,608**	46,795
Attributable to:		
Equity holders of the parent company	**35,063**	46,065
Minority interest	**545**	730
	35,608	46,795

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2007	2006
OPERATING ACTIVITIES		
Income before tax	**146,811**	171,236
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortisation and impairment	**39,372**	39,450
Exploration expenditures written off	**1,660**	1,447
(Gains) losses on foreign currency transactions and balances	**(559)**	(1,197)
(Gains) losses on sales of assets and other items	**(188)**	(2,371)
Termination benefits	**8,633**	0
Changes in working capital (other than cash and cash equivalents):		
• (Increase) decrease in inventories	**(2,434)**	(2,850)
• (Increase) decrease in trade and other receivables	**(6,493)**	1,060
• (Increase) decrease in net current financial derivative instruments	**1,307**	(12,450)
• Increase (decrease) current financial investments	**(2,327)**	5,810
• Increase (decrease) in trade and other payables	**10,447**	(3,496)
Taxes paid	**(102,422)**	(108,174)
• (Increase) decrease in non-current items related to operating activities	**119**	128
Cash flows provided by operating activities	**93,926**	88,593
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(63,785)**	(45,177)
Exploration expenditures capitalised	**(4,569)**	(4,188)
Changes in other intangibles	**(7,186)**	(10,507)
Change in long-term loans granted and other long-term items	**(652)**	(726)
Proceeds from sale of assets	**1,080**	3,423
Cash flows used in investing activities	**(75,112)**	(57,175)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in NOK million)	For the year ended 31 December 2007	2006
FINANCING ACTIVITIES		
New long-term borrowings	**1,723**	97
Repayment of long-term borrowings	**(2,876)**	(2,270)
Distribution to minority shareholders	**(327)**	(741)
Dividend paid*	**(25,695)**	(17,756)
Treasury shares purchased	**(217)**	(1,012)
Norsk Hydro ASA merger balance	**18,687**	(10,025)
Net short-term borrowings, bank overdrafts and other**	**797**	329
Cash flows used in financing activities	**(7,908)**	(31,378)
Net increase (decrease) in cash and cash equivalents	**10,906**	40
Effect of exchange rate changes on cash and cash equivalents	**(160)**	42
Cash and cash equivalents at the beginning of the period	**7,518**	7,436
Cash and cash equivalents at the end of the period	**18,264**	7,518
Interest paid	**3,709**	3,611
Interest received	**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 shareholders of Statoil ASA and Norsk Hydro ASA (Hydro) approved at extraordinary General Meetings on 5 July 2007 a merger between Statoil ASA and the oil and gas activities of Norsk Hydro ASA (Hydro Petroleum). The merger was effective 1 October 2007 and Statoil ASA's name changed to StatoilHydro ASA as of that date.

StatoilHydro's business consists principally of the exploration, production, transportation, refining and marketing of petroleum and petroleum-derived products.

StatoilHydro ASA is listed on the Oslo Stock Exchange (Norway) and the New York Stock Exchange (USA). The address of its registered office is Forusbeen 50, N-4035 Stavanger, Norway.

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. See note 31 IFRS transition.

Given that both Statoil ASA and Norsk Hydro ASA were under the control of the Norwegian State, the merger between former Statoil ASA and Hydro Petroleum, resulting in StatoilHydro ASA, 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 is 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 have been adjusted to conform to the accounting policies of Statoil ASA.

Operating expenses in the statements of income are presented as a combination of function and nature in conformity with industry practice. Cost of goods sold 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); IFRS 8 *Operating Segments* (effective for accounting periods beginning on or after 1 January 2009); IFRIC 11 IFRS 2: *Group and Treasury Share Transactions* (effective 1 March 2007); IFRIC 13 *Customer Loyalty Programmes* (effective for accounting periods beginning on or after 1 July 2008).

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 some changes to the statement of recognised income and expense. Any restatements or reclassifications will require an additional balance sheet including the restatements for the earliest balance sheet period presented. There will be no effect on the Group's reported net income or equity.

The revised version of IFRS 3 *Business Combinations* will be applicable to business combinations occurring in accounting 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. The Group has not completed its evaluation of the effect of the future adoption of this amendment.

The amendments to IAS 32 and IAS 1 issued in February 2008 are effective for annual periods beginning on or after 1 January 2009 and the Group has not completed its evaluation of the effect of the future adoption of these amendments.

The amendment to IFRS 2 *Share-based payment* issued in January 2008, IFRIC 12 *Service Concession Arrangements* (effective 1 January 2008) and IFRIC 14 IAS 19 - *The Limit on a Defined Benefit Asset, Minimum Funding Requirements and their interaction* (effective 1 January 2008) are 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 held by the Group 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, 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 costs such as employee benefits 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 partner's 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.

Translation of financial statements of foreign operations

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 foreign subsidiaries (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 foreign subsidiaries 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 licences for which no decision has been made to develop are treated as asset purchases, whereas 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 (see Basis of preparation above), are accounted for using the purchase method of accounting. The purchased identifiable tangible and intangible assets, liabilities and contingent liabilities are measured at their fair values at the date of purchase. Any excess of the cost of purchase over the net fair value of the identifiable assets purchased 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 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 cost of goods sold 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 vesting period of two years. The awarded shares are accounted for as salary 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; 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 statement of Income for the year comprises current and deferred tax expense. Income tax is recognised in the statement of income except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

Current tax is the expected tax payable on the taxable income for the year and any adjustment to tax payable in respect of previous years. Uncertain tax positions and potential tax exposures are analysed individually and the best estimate of the probable amount for liabilities to be paid (unpaid potential tax exposure amounts, including penalties) and virtually certain amount for assets to be received (disputed tax positions for which payment has already been made) in each case is recognised within current tax or deferred tax as appropriate. Interest income and interest expenses relating to tax issues are estimated and recorded in the period in which they are earned or incurred, and are presented as financial items in the statement of income.

Deferred tax 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 per cent. The special tax is applied to relevant income in addition to the standard 28 per cent income tax, resulting in a 78 per cent 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 cent 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.

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. 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. Impairment of unsuccessful wells is reversed, as applicable, to the extent that the events or circumstances that triggered the original impairment have changed.

Expenditures to drill and equip exploratory wells that find proved reserves are capitalised and depreciated using the unit of production method based on proved developed reserves expected to be recovered from the well. Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells 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. Pre-production costs are expensed as incurred.

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.

Depreciation of production installations and field-dedicated transport systems for oil and gas is calculated using the unit of production method based on proved developed reserves expected to be recovered from the area during the concession or contract period. Depreciation of other assets and of transport systems used by several fields is calculated on the basis of their estimated useful lives, using the straight-line method. Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately. For exploration and production (E&P) assets the 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. Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

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.

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.

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 the 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 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
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 "Measurement of fair value" below. Financial assets are derecognised from the balance sheet when the contractual rights to the cash flows either expire or are transferred.

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.

The Group classifies its financial assets at initial recognition according to the following categories; financial investments at fair value through profit or loss; loans and receivables; and as available-for-sale (AFS) financial assets.

Non-current financial investments comprise unlisted securities, commercial papers, bonds and listed securities.

Unlisted securities are classified as AFS. AFS financial assets are carried on the balance sheet at fair value, with gains or losses being recognised as a separate component of equity until the investment is derecognised or until the investment is determined to be impaired, at which time the cumulative gain or loss previously reported in equity is included in the statement of income.

Non-current commercial papers, bonds and listed 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 gains and losses recognised through profit or loss.

Current financial investments comprise short-term investments and are in the category of fair value through profit or loss.
Financial investments at fair value through profit or loss are assets classified as held for trading and other assets designated at inception. Assets are carried on the balance sheet at fair value with gains or losses recognised in the income statement.

Non-current loans and receivables comprise long term interest bearing receivables and are classified as financial receivables in the Balance sheet.

Trade and other receivables are in the category of loans and receivables.

Loans and receivables are carried at amortised cost using the effective interest method. Gains and losses are recognised in 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. Balances are written off when the probability of recovery is assessed as being remote.

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.

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

For assets carried at amortised cost, if there is objective evidence that an impairment loss on loans and receivables carried at amortised cost has been incurred, the carrying amount of the asset is reduced. Any subsequent reversal of an impairment loss is recognised in the income statement.

If an available-for-sale financial asset is impaired (significant or prolonged decline), the difference between cost and fair value is transferred from equity to the income statement. Impairments of debt instruments are reversed to the income statement as applicable. Impairments of equity instruments classified as available-for-sale are not reversed.

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.

Financial liabilities
Interest-bearing debenture bonds, bank loans and other debt classified as financial liabilities, are initially recognised at fair value when the Group becomes party to the contractual provisions of the instrument. After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Financial liabilities are derecognised from the balance sheet when the contractual obligation expires, is discharged or cancelled. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognised respectively in interest income and other financial items and interest and other finance expenses.

Financial liabilities are presented as current if the 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.

Pension obligations
The Company and certain of its subsidiaries have 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.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognised in the Statement of income as operating expenses.

Past service costs are 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 resultant gain or loss is recognised in the income statement during the period which the settlement or curtailment occurs.

Actuarial gains and losses are recognised in full in the Group statement of recognised income and expense in the period in which they occur.

Contribution to defined contribution schemes are recognised in the Statement of income in the period in which the contribution amounts are earned by the employees.

Provisions
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 are not recognised, but are disclosed when an inflow of economic benefits is probable.

Asset retirement obligations
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. 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.

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

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.

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. An important exception to this rule is that contracts that were entered into and continue 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, are not accounted for as financial instruments. This exception applies to a significant number of contracts for the purchase or sale of crude oil and natural gas.

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. Any gains or losses arising from changes in fair value are recognised in profit or loss for the period.

For those derivatives designated as hedges 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 are used when 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 are taken to profit or loss being recorded in the same line. For hedged items carried at amortised cost, the adjustment is amortised through the income statement such that it is fully amortised by maturity. When an unrecognised firm commitment is designated as a hedged item, this gives rise to an asset or liability in the balance sheet, representing the cumulative change in the fair value of the firm commitment attributable to the hedged risk. 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
The fair values of quoted financial assets and liabilities and derivative instruments are determined by reference to bid and ask prices respectively, at the close of business on the balance sheet date. Fair values of financial instruments quoted in active markets such as but not limited to commodity based futures, exchange traded option contracts and equity instruments are based on quoted market prices obtained from the relevant exchanges or clearing houses.

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. 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, underlying indexes in the contracts, and assumptions of forward prices and margins where market prices are not available. Likewise, fair value of interest and currency swaps are estimated based on relevant quotations from active markets, quotes of comparable instruments, and other appropriate valuation techniques. The fair value of options not traded in active markets is estimated by use of appropriate valuation models developed and used by third parties.

The fair values of financial instruments not traded in active markets are the Group's best estimates of the gain or loss that would have been realised if the contracts had been closed out at year end, but actual results could vary due to assumptions used.

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:

Method of accounting applied for the Hydro Petroleum merger
As described under Basis of preparation above, 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.

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.

Key sources of estimation uncertainty
The preparation of consolidated financial statements require that management make estimates and assumptions.

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*.* Oil and gas reserves have been estimated by internal experts in accordance with industry standards. 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.

Reserve estimates are used when testing upstream assets for impairment. Proved and proved developed reserves are used when calculating the unit of production rates used for depreciation, depletion, and amortisation. Future changes in 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 and for asset retirement obligation, 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 depreciation and amortisation or 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.

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 license or a development decision is planned in the near future.

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.

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, 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. 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 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 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.

8.1.3 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 is regulated in a merger plan between the two parties. In the merger plan it is stated that the management structure and management systems of the merged company principally will be based on former Statoil's model. The merger was effective 1 October 2007.

As a result of the merger 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 hold 32.7 per cent and former Statoil's shareholders hold 67.3 per cent of the merged company, StatoilHydro ASA. The Norwegian State held 65 per cent in the merged company as of 31 December 2007. For more information regarding changes in organisation and preparation of the Financial statements for the StatoilHydro group due to the merger, see information in note 2.

Prior to the merger Hydro Petroleum comprised the oil and gas business of Hydro, along with Hydro's wind power business and interests in a power generation company and an information technology subsidiary. Hydro Petroleum was an international oil and energy enterprise and a major player in the Nordic and European energy markets. It developed, produced and supplied oil and gas and took an active role in developing new energy forms such as wind power and hydrogen. In recent years, Hydro Petroleum's businesses have grown as a result of substantial investments undertaken by Hydro, including the acquisition of Saga Petroleum ASA, a Norwegian-based oil company, in 1999, and new oil and gas licenses on the NCS obtained from the Norwegian State. Based on production, Hydro Petroleum was the second largest operator on the NCS and, as a stand-alone enterprise, would be among the leading international oil and energy companies.

For all periods presented, the financial information of Hydro Petroleum has been adjusted to conform to the accounting policies of StatoilHydro 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 the Norwegian public limited companies act section 14-11, StatoilHydro and Hydro are jointly and severally liable for certain guarantee commitments entered into by Hydro prior to the merger. The total amount StatoilHydro is jointly liable for is approximately NOK 8.3 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.

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 is included in the 2006 balance sheet and 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.

StatoilHydro has, 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 is 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 and Balance Sheet as at 31 December 2006. The column "Former 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, b) include other merger related adjustments (including the merger receivable and assumption of certain debt obligations from Norsk Hydro ASA), and c) eliminate internal transactions between the merged companies.

Condenced Statements of Income and Balance sheets

	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
Total non-current assets	100,508	233,074	(934)	332,648
Total current assets	24,446	86,872	14,857	126,175
Total assets	124,954	319,946	13,923	458,823
Total equity	32,238	126,517	10,652	169,407
Total non-current liabilities	54,727	113,313	6,526	174,566
Total current liabilities	37,989	80,116	(3,255)	114,850
Total equity and liabilities	124,954	319,946	13,923	458,823

8.1.4 Significant acquisitions

On 27 April 2007 StatoilHydro entered into an agreement whereby StatoilHydro made an all-cash offer to acquire all shares of North American Oil Sands Corporation (NAOSC) at a price of CAD 20 per share. The total transaction value was approximately CAD 2.2 billion, equivalent to about USD 2 billion. NAOSC, a Calgary-based company, was formed in 2001. 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 is not considered a business combination.

On 15 September 2006 StatoilHydro entered into an agreement to acquire working interests in two US Gulf of Mexico deepwater discoveries and one exploration prospect at a cost of USD 700 million. The assets are located in the Greater Tahiti and Walker Ridge areas. As a result of the agreement, StatoilHydro has a 17.5 per cent working interest in the Caesar discovery and a 12.5 per cent working interest in the Big Foot discovery. The transaction was completed in the fourth quarter of 2006 and was recorded in the segment International Exploration and Production. The transaction is not considered a business combination.

On 3 November 2006 StatoilHydro entered into an agreement with Anadarko Petroleum Corporation to acquire two of Anadarko's US Gulf of Mexico discoveries and one prospect at a cost of USD 901 million. The assets are located in the Greater Tahiti and Walker Ridge areas. As a result of the agreement StatoilHydro has a 27.5 per cent working interest in the Big Foot discovery, including the additions from the agreement mentioned above. The transaction was completed in the first quarter of 2007 and was recorded in the segment International Exploration and Production. The transaction is 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 at estimated market prices.

Operating segments align with internal management reporting, and are determined based on differences in the nature of their operations, products and services. The measure of segment profit is Net operating income.

Segment data for the years ended 31 December, 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 2007							
Revenues third party (including 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 equity accounted investments	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
Depreciation, amortisation and impairment losses	23,030	11,103	1,845	2,833	561	0	39,372
Significant non-cash items other than depreciation, amortisation and impairment losses							
- Pension cost **	5,300	738	700	700	1,300	0	8,738
- Commodity derivatives	(2,920)	577	3,318	1,031	(88)	0	1,918
- Exploration expenditures written off	50	1,610	0	0	0	0	1,660
Impairment losses recognised in profit or loss	0	1,246	250	937	(3)	0	2,430
Net operating income	123,150	12,161	1,562	3,776	(2,260)	(1,185)	137,204
Segment non-current assets*	153,434	107,478	35,755	27,825	20,515	0	345,007
Investments in affiliates	125	2,253	4,516	1,066	461	0	8,421
Additions to PP&E and intangible assets	31,100	36,200	2,100	4,800	800	0	75,000

* Excluding “Investments in affiliates”.

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

(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							
(including 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 equity							
accounted investments	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
Depreciation, amortisation and							
impairment losses	20,938	14,370	1,425	2,280	437	0	39,450
Significant non-cash items							
other than depreciation,							
amortisation and impairment losses							
- Exploration expenditures							
written off	177	1,270	0	0	0	0	1,447
- Commodity derivatives	69	(354)	(6,894)	(136)	12	0	(7,303)
Impairment losses recognised							
in profit or loss	230	4,902	0	57	0	0	5,189
Net operating income	135,140	3,917	21,693	7,280	(1,427)	(439)	166,164
Segment non-current assets*	152,093	96,172	30,396	25,771	19,660	0	324,092
Investments in affiliates	235	2,381	4,771	964	205	0	8,556
Additions to PP&E and							
intangible assets	29,200	28,900	3,200	2,500	500	0	64,300

* Excluding “Investments in affiliates”.

StatoilHydro ASA offered early retirement to employees above the age of 58 years (contingent upon certain conditions). StatoilHydro has, subsequent to the merger, recorded a total expense of NOK 10.7 billion before tax related to restructuring expenses and other expenses related to the merger. The major part of these expenses are related to pensions and early retirement packages offered to all employees in StatoilHydro ASA above the age of 58 years. The total expense impacts the net operating income of all segments, and most significantly the segment Exploration and Production Norway. For more information regarding consequences of the merger, see information in note 3.

Impairments of NOK 4.9 billion before tax in 2006 were related to Gulf of Mexico property, plant and equipment.

The decrease in the Natural Gas segment's net operating income in 2007, compared to 2006, is mainly due to a reduction in prices of piped natural gas and a negative change in the fair value of derivatives.

Geographical areas

StatoilHydro is present in 40 countries, and manages its four business segments on a worldwide basis. In presenting information on the basis of geographical areas, revenues from external customers is attributed to countries from which StatoilHydro derives revenues.

Segment assets are based on the geographical location of the assets.

Segment data for the year ended 31 December, 2007, and 2006 is presented below:

(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	5,094	9,114	30,122
Total revenues (excluding equity in net income of affiliates)	261,057	70,665	49,024	114,392	27,050	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	10,363	8,583	36,874
Total revenues (excluding equity in net income of affiliates)	240,592	83,719	48,539	107,682	40,271	520,803

Segment assets by geographic areas

(in NOK million)	2007	2006
Year ended 31 December		
Norway	204,401	200,220
United States	38,672	33,841
Azerbaijan	16,279	17,444
Angola	15,906	16,371
Canada	14,423	3,160
Algeria	8,371	9,699
Other areas	33,571	31,189
Total non-current asset (excluding deferred tax, pension and financial non-current items)	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 work-years)	For the year ended 31 December 2007	2006
Salaries	17,243	15,980
Pension cost	3,131	2,281
Payroll tax	2,930	2,368
Other social benefits	1,997	1,567
Total payroll costs	25,301	22,196
Average number of work-years	27,641	26,899

Pension cost is exclusive of termination benefits.

Total payroll costs are partly charged to partners of StatoilHydro-operated licences, partly capitalised and partly expensed. The expensed payroll costs are mainly included in Operating expenses, Selling, general and administrative expenses and Exploration expenses.

The calculation of pension costs and pension assets/liabilities is described in note 21.

Share based compensation
StatoilHydro's Share Saving Plan provides employees with the option 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 246 million and NOK 96 million related to the 2007 and 2006, respectively. At 31 December 2007 the amount of compensation cost yet to be expensed throughout the vesting period is NOK 533 million. For the 2008 program (granted in 2007) the estimated compensation expense for 2008 is NOK 331 million.

8.1.7 Other expenses

Auditors' remuneration

(in NOK million)	Audit fee	Audit related fee	Total
2007			
Ernst & Young - Norway	18.6	7.4	26.0
Ernst & Young - outside Norway	26.2	1.1	27.3
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 6.1 and NOK 4.0 million for 2007 and 2006, respectively.

The increase in audit fees and audit related fees from 2006 to 2007 is 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 1,969 million and NOK 1,616 million in 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 statement of income.

8.1.8 Financial items

(in NOK million)	2007	2006
Foreign exchange gains and losses non-current financial liabilities	5,944	3,190
Other foreign exchange gains and (losses)	4,099	1,267
Net foreign exchange gains and losses	10,043	4,457
Dividends received	523	554
Gain (loss) on securities	(723)	646
Interest income securities	338	612
Interest income non-current financial receivables	197	204
Interest and other financial income current financial assets	1,970	1,659
Interest and other financial income	2,305	3,675
Capitalised interests	2,680	3,255
Accretion expense asset retirement obligation	(2,099)	(1,304)
Interest expense non-current loans inclusive financial derivatives	(1,948)	(3,424)
Interest and other finance expenses financial liabilities	(1,374)	(1,587)
Interest and other financial expenses	(2,741)	(3,060)
Net financial Items	9,607	5,072

The net gain on financial assets available for sale recognised directly in equity was NOK 1,039 million in 2007, compared to a net loss of NOK 524 million in 2006.

8.1.9 Income taxes

Income before income taxes consists of

(in NOK million)	2007	2006
Norway offshore	124,707	151,556
Norway onshore	7,331	6,402
Other countries upstream 1)	13,727	7,038
Other countries downstream 1)	1,046	6,240
Total income before tax	146,811	171,236

Significant components of income tax expense were as follows

(in NOK million)	2007	2006
Norway offshore	98,203	111,095
Norway onshore	1,924	1,149
Other countries upstream 1)	9,928	628
Other countries downstream 1)	535	5,434
Uplift benefit	(4,365)	(3,759)
Current income tax expense	106,225	114,547
Norway offshore	(555)	6,065
Norway onshore	373	856
Other countries upstream 1)	(3,688)	(2,669)
Other countries downstream 1)	(185)	589
Deferred tax expense	(4,055)	4,842
Total income tax expense	102,170	119,389

1) Includes taxes liable to Norway on income in other countries.

Reconciliation of Norwegian nominal statutory tax rate of 28 per cent to effective tax rate

(in NOK million)	2007	2006
Norway offshore	124,707	151,556
Norway onshore	7,331	6,402
Other countries upstream	13,727	7,038
Other countries downstream	1,046	6,240
Total income before tax	146,811	171,236
Calculated income taxes at statutory rates:		
Calculated income taxes at statutory rate (norwegian statutory tax rate 28%)	41,107	47,946
Petroleum surtax at statutory rate (norwegian special tax rate 50%)*	62,353	75,357
Uplift*	(4,365)	(3,759)
Other countries upstream (average statutory tax rates)	2,397	1,019
Other countries downstream (average statutory tax rates)	57	(754)
Other items	621	(420)
Income tax expense	102,170	119,389
Effective tax rate	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 per cent is levied after deducting uplift, an investment tax credit. Uplift is deducted by 7.5 per cent per year for four years, as from the year of investment. At the end of 2007 unrecognised uplift credits amount to NOK 17.3 billion.

Deferred tax assets and liabilities comprise:

(in NOK million)	Inventory	Other current items	Tax losses carry forwards	Property, plant and equipment	Exploration expenditure	ARO	Pensions	Other non-current items	Total
Deferred tax at 31 December 2006									
Deferred tax assets	1,848	4,231	3,670	5,747	0	30,360	5,215	3,683	54,754
Deferred tax liabilities	0	(8,855)	0	(92,835)	(16,288)	0	0	(8,052)	(126,030)
Net asset/(liability) at 31 December 2006	1,848	(4,624)	3,670	(87,088)	(16,288)	30,360	5,215	(4,369)	(71,276)
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)

Analysis of movements during the year	2007	2006
Deferred tax liability at 1 January	71,276	69,300
Charged/(credited) to the income statement	(4,055)	4,842
Charged/(credited) to equity	175	(2,321)
Translation differences and other	(712)	(545)
Deferred tax liability at 31 December	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.

Deferred tax assets
At the end of 2007, StatoilHydro had recognised tax losses carry-forwards of NOK 2.9 billion, primarily in the US and Azerbaijan, since it is considered probable that taxable profit will be available and there are sufficient taxable temporary differences to utilise the unused tax loss carry-forwards. Only a minor part of the tax losses carry-forwards amounts expire before 2019.

Unrecognised deferred tax assets

(in NOK million)	2007	2006
Deductible temporary differences	3,860	3,362
Tax losses carry forward	3,143	2,059

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, weighted average number of ordinary shares outstanding has been set as the total of 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 for 2007 was based on the net income attributable to ordinary shareholders of the parent company, NOK 44 096 million (2006: NOK 51,117), and a weighted average number of ordinary shares outstanding during the year ended 31 December 2007 of 3,195,866,843 (2006: 3,230,849,707), calculated as follows:

	2007	2006
Net income attributable to Equity holders of the parent company (in NOK million)	44,096	51,117
Weighted average number of ordinary shares outstanding (In thousands of shares)		
Issued ordinary shares at 1 January	2,166,144	2,189,586
Effect of treasury shares held	(21,681)	(28,557)
Effect of shares issued in the merger with Hydro Petroleum	1,051,404	1,069,822
Weighted average number of ordinary shares	3,195,867	3,230,850
Earnings per share for income attributable to equity holders of the company - basic and diluted (NOK)	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 plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Construction in progress	Total
Cost at 31 December 2005	11,130	428,090	41,816	13,271	546	62,032	556,885
Additions and transfers	678	51,972	947	1,670	2,345	7,735	65,347
Disposals assets at cost	(510)	(3,778)	(805)	(131)	(87)	(240)	(5,551)
Effect of movements in foreign exchange - assets	430	(4,251)	(800)	149	0	(1,851)	(6,323)
Cost at 31 December 2006	11,728	472,033	41,158	14,959	2,804	67,676	610,358
Accumulated depr. and impairment losses at 31 December 2005	(7,539)	(263,975)	(23,424)	(4,412)	(358)	(1,784)	(301,492)
Depreciation and amorisation for the year	(718)	(29,809)	(1,831)	(1,267)	(261)	0	(33,886)
Impairment losses for the year	0	(5,183)	(30)	0	0	0	(5,213)
Depreciation on additions for the year	0	(3,740)	0	0	0	0	(3,740)
Disposals depreciation	510	3,868	87	54	87	36	4,642
Effect of movements in foreign exchange – depreciation and impairment losses	(291)	1,804	310	(55)	0	(274)	1,494
Accumulated depr. and impairment losses at 31 December 2006	(8,038)	(297,035)	(24,888)	(5,680)	(532)	(2,022)	(338,195)
Balance at 31 December 2006	3,690	174,998	16,270	9,279	2,272	65,654	272,163

(in NOK million)	Machinery, equipment and transportation equipment	Production plants oil and gas, incl. pipelines	Refining and manufacturing plants	Buildings and land	Vessels	Construction in progress	Total
Cost at 31 December 2006	11,728	472,033	41,158	14,959	2,804	67,676	610,358
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	12,879	523,214	41,100	14,816	4,697	48,925	645,631
Accumulated depr. and impairment losses at 31 December 2006	(8,038)	(297,035)	(24,888)	(5,680)	(532)	(2,022)	(338,195)
Depreciation 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)
Disposals depreciation	174	2,820	118	618	158	(16)	3,872
Effect of movements in foreign exchange – depreciation and impairment losses	170	4,425	538	161	28	307	5,629
Accumulated depr. and impairment losses at 31 December 2007	(8,583)	(325,135)	(25,693)	(5,561)	(576)	(1,731)	(367,279)
Balance at 31 December 2007	4,296	198,079	15,407	9,255	4,121	47,194	278,352
Estimated useful lives (years) on initial recognition	3 - 10	*	15-20	20 - 33	20 - 25		

In 2007 and 2006, capitalised borrowing cost amounted to NOK 2.7 billion and NOK 3.3 billion, respectively. In addition to depreciation, amortisation and impairment losses specified above, intangible assets, see note 12, have been amortised by NOK 787 million and NOK 351 million in 2007 and 2006, respectively.

Transfer of assets to Property, plant and equipment from Intangible assets in 2007 and 2006 amounted to NOK 3.2 billion and NOK 3.3 billion, respectively.

*Depreciation according to Unit of production, see note 2.

ASSET IMPAIRMENTS

In assessing whether a write-down is required in the carrying amount of a potentially impaired asset, the assets 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 2007 and 2006 using a real post-tax discount rate of 6.5% (2006 6.5%). The discount rate derives from the Group's post-tax weighted average cost of capital (WACC).

In 2007 an impairment charge of NOK 1.6 billion before tax was recorded in Depreciation, depletion and impairment losses related to International Exploration and Production assets (Property, plant and equipment) in the South China Sea and in the Gulf of Mexico and related to Manufacturing and Marketing assets (Property, plant and equipment) in Energy and Retail in Sweden.

In 2006 an impairment charge of NOK 5.2 billion before tax was recorded in Depreciation, depletion and impairment losses, mainly related to the International Exploration and Production assets (Property, plant and equipment) in the Gulf of Mexico, which amounted to NOK 4.9 billion before tax.

8.1.12 Intangible assets

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2005	19,742	6,884	26,626
Acquisitions through business combinations	2,719	485	3,204
Other additions	10,216	44	10,260
Disposals intangible assets at cost	(362)	(47)	(409)
Transfers of intangible assets	(3,343)	0	(3,343)
Exploration expenditures written off	(1,447)	0	(1,447)
Effect of movements in foreign exchange – intangible assets	(1,429)	(536)	(1,965)
Cost at 31 December 2006	26,096	6,830	32,926
Accumulated amortisation and impairment losses at 31 December 2005	0	(1,508)	(1,508)
Amortisation and impairment losses for the year	0	(351)	(351)
Disposals amortisation	0	47	47
Effect of movements in foreign exchange - Amortisation and impairment losses	0	91	91
Accumulated amortisation and impairment losses at 31 December 2006	0	(1,721)	(1,721)
Book value at 31 December 2006	26,096	5,109	31,205

(in NOK million)	Exploration expenditure	Other	Total
Cost at 31 December 2006	26,096	6,830	32,926
Other additions	23,237	742	23,979
Disposals intangible assets at cost	0	(191)	(191)
Transfers of intangible assets	(3,090)	(79)	(3,169)
Exploration expenditures written off	(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)
Amortisation and impairment losses for the year	0	(787)	(787)
Disposals amortisation	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)
Book value at 31 December 2007	40,511	4,339	44,850

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite useful lives are amortised systematically over their estimated economic lives, ranging between 10-20 years.

Additions in Intangible assets of NOK 24 billion in 2007 relate mainly to capitalised signature bonuses and other exploration rights in connection with acquisition of assets from Anadarko Petroleum Corporation and North American Oil Sands Corporation.

Included in Other Intangibles is goodwill of NOK 3 billion.

The amortisation and impairment charges are recognised as depreciation, depletion and impairment losses in the statement of income.

8.1.13 Equity accounted investments

(in NOK million)	2007	2006
Carrying amount equity accounted investments	8,421	8,556
Net income (loss) after tax from equity accounted investments	609	679

Summary of financial information for significant associates accounted for by the equity method is shown below. StatoilHydro's investment in these companies is included in Equity accounted investments.

Equity accounted investments – 100 per cent amounts

(in NOK million)	Country of incorporation	Assets	Liabilities	Revenues	Net income	Share held
2007						
South Caucasus PHC Ltd	Azerbaijan	7,609	334	762	110	25.50%
BTC Pipeline Company	Azerbaijan	29,593	2,626	6,826	3,173	8.71%
2006						
South Caucasus PHC Ltd	Azerbaijan	8,715	513	87	51	25.50%
BTC Pipeline Company	Azerbaijan	31,600	1,770	2,535	532	8.71%

South Caucasus Pipeline Holding Company Limited is responsible for operating a gas pipeline from Baku in Azerbaijan to Turkey. The pipeline became operational in 2007.

BTC Pipeline Company's operates the BTC (Baku-Tbilisi-Ceyhan) pipeline. The BTC company is organised as an entity where participants through contractual agreements have joint control of the entity. The entity consequently is reflected as an equity accounted investment.

8.1.14 Non-current financial assets

Non-current financial investments

(in NOK million)	At 31 December 2007	2006
Available for sale investments	3,291	2,262
Commercial papers	605	1,365
Bonds	7,140	5,785
Marketable equity securities	4,230	4,600
Total non-current financial investments, see note 28	15,266	14,012

All non-current financial investments are recorded at fair value. Of the non-current financial investments, NOK 11,975 million relate to the investment portfolio held by the Group's captive insurance subsidiary and is accounted for using the fair value option. NOK 41 million of the Group's captive insurance subsidiary portfolio is used as collateral for trading with OTC instruments.

Fair value changes for available for sale investments are recognised in Equity - other reserves. Fair value changes for Commercial papers, Bonds and Marketable equity securities are recognised in the statement of income.

Non-current financial receivables

(in NOK million)	At 31 December 2007	2006
Interest bearing receivables	2,784	3,202
Non-interest bearing receivables	731	1,139
Total non-current financial receivables, see note 28	3,515	4,341

Of the interest-bearing receivables at 31 December 2007 a balance of NOK 934 million relates to the BTC project financing structure and NOK 1,086 million relates to the Sincor project financing structure. Corresponding balances for 31 December 2006 were NOK 1,133 million for the BTC structure and NOK 1,310 million for the Sincor structure.

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 cost of goods sold during the year.

(in NOK million)	At 31 December 2007	2006
Crude oil	8,097	6,537
Petroleum products	7,186	6,233
Other	2,413	2,486
Total	17,696	15,256

8.1.16 Trade and other receivables

(in NOK million)	At 31 December 2007	2006
Trade receivables	62,060	57,926
Receivables due from joint ventures	6,115	4,294
Receivables by equity accounted investments and other related parties	1,203	139
Total current trade and other receivables	69,378	62,359

The majority of receivables are due within 30 days.

8.1.17 Current financial investments

(in NOK million)	At 31 December 2007	2006
Commercial papers	3,204	825
Other	155	207
Total current financial investments, see note 28	3,359	1,032

All current financial investments are recorded at fair value with gains and losses recognised in the Statement of income. All balances at 31 December 2007 are considered as held for trading investments. The cost price for current financial investments at 31 December 2007 and 2006 was NOK 3,400 million and NOK 912 million respectively.

8.1.18 Cash and cash equivalents

(in NOK million)	At 31 December 2007	2006
Cash at bank	3,837	2,764
Time deposits with maturity of less than three months	14,427	4,754
Total cash and cash equivalents, see note 28	18,264	7,518

The overdraft bank balances and overdraft facilities are included under Current financial liabilities in note 20.

8.1.19 Shareholder's equity

(in NOK million, except share data)	Number of shares issued	Share capital	Treasury shares	Additional paid-in capital	Additional paid-in capital related to treasury shares	Retained earnings	Other reserves: Available for sale financial assets	Other reserves: Currency translation adjustments	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
Equity settled share based payments				61					61		61
Treasury shares purchased			(53)		(3,509)				(3,562)		(3,562)
Merger related adjustments consist of change in merger balance with Norsk Hydro ASA						(11,768)			(11,768)		(11,768)
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)
Effectuation of annulment, see information below	(20,158,848)	(50)	50	(3,426)	3,426				0		0
Equity settled share based payments				112					112		112
Treasury shares purchased (net of allocated shares)			(2)		(180)				(182)		(182)
Merger related adjustments						143			143		143
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

* For detailed information, see Consolidated statements of recognised income and expense.

For information regarding changes in equity related to the merger with Hydro Petroleum, see information in note 3. Merger related adjustments in 2006 consists of change in the Norsk Hydro ASA merger receivable.

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 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 2007 the Norwegian State had an ownership interest in StatoilHydro of 65 per cent. The Norwegian State is defined as a related party, see note 26.

After the annulment, 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 2007 a total of 1,272,790 treasury shares were purchased for NOK 217 million. At 31 December 2007 StatoilHydro had 2,195,213 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 9.12 and NOK 8.20 in 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 2007 of NOK 8.50 per share, amounting to a total dividend of NOK 27.1 billion, will be proposed at the Annual General Meeting in May 2008. The proposed dividend is not recognised as a liability in the financial statements.

Retained earnings available for distribution of dividends at 31 December 2007 is limited to the retained earnings of the parent company based on Norwegian accounting principles and legal regulations and amounted to NOK 137,638 million (before provisions for proposed dividend for the year ended 31 December 2007 of NOK 27,085 million). This differs from retained earnings in the consolidated financial statements of NOK 140,909 million. In accordance with legal requirements dividends is not allowed to reduce the shareholders' equity of the parent company below 10 per cent of total assets.

8.1.20 Financial liabilities

Non-current financial liabilities

	Weighted average interest rates in %		Balance in NOK million at 31 December	
	2007	2006	2007	2006
Financial liabilities measured at amortised cost				
Unsecured debenture bonds				
US dollar (USD)	7.00	7.07	17,418	20,348
Norwegian kroner (NOK)	6.21	4.00	500	500
Euro (EUR)	5.62	5.52	5,316	6,802
Japanese yen (JPY)	1.50	1.08	869	1,470
Great British pounds (GBP)	6.13	6.13	2,429	2,780
Total			26,532	31,901
Unsecured bank loans				
US dollar (USD)	5.09	5.25	2,530	1,288
Secured bank loans				
US dollar (USD)	7.45	7.29	2,683	3,335
Other currencies	6.57	4.60	80	333
Financial lease liabilities			4,011	2,764
Other liabilities			38	217
Total			9,342	7,937
Financial liabilities measured at amortised cost adjusted for fair value of hedged risk				
Unsecured debenture bonds subject to hedge accounting				
US dollar (USD)	6.29	6.29	7,845	8,708
Euro (EUR)	5.13	5.13	1,627	1,712
Swiss franc (CHF)	4.01	4.01	982	1,065
Japanese yen (JPY)	0.47	0.47	241	260
Total			10,695	11,745
Grand total liabilities outstanding			46,569	51,583
Less current portion			2,196	2,367
Total non-current liabilities			44,373	49,215

The table above contains amortised cost adjusted for fair value of hedged risk of loans per currency for the bonds that qualify for hedge accounting. The table therefore does not illustrate the economic effects of agreements entered into to swap the various currencies to USD. For further information see note 28.

Weighted average interest rates are calculated on the loans per currency and do not reflect swap agreements.

Details of largest unsecured debenture bonds:

Bond agreement	Fixed interest rate	Maturity (year)	Balance in million NOK at 31 December 2007	2006
USD 500 million	6.500 %	2028	2,675	3,091
USD 500 million	5.125 %	2014	2,704	3,125
USD 480 million	7.250 %	2027	2,600	3,014
USD 375 million	5.750 %	2009	2,026	2,339*
USD 300 million	7.750 %	2023	1,623	1,882
USD 300 million	6.360 %	2009	1,623	1,882
EUR 500 million	5.125 %	2011	3,961	4,092
EUR 300 million	6.250 %	2010	2,388	2,479
GBP 225 million	6.125 %	2028	2,432	2,760

* Net after buy-backs NOK 1,765 million and NOK 2,035 million in 2007 and 2006, respectively.

Currency swaps are used for risk management purposes. Unsecured debenture bond liabilities are either denominated in US dollar, amounting to NOK 25,263 million and the amount swapped into US dollar, amounted to NOK 11,964 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 debentures bond contracts with fixed interest rates. As a result of this the majority of the portfolio is swapped from fixed to floating interest rate. Financial derivatives are not classified as interest bearing liabilities, and are therefore not included in the table above. For further information, see notes 27 and 28.

Substantially all unsecured debenture 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 guarantee commitments amounting to USD 45 million, mortgage of shares in a subsidiary and investments in associated companies with a combined book value of NOK 2,294 million, collateral in bank deposits with book value of NOK 2,020 million, and the Group's pro-rata share of income from certain applicable projects.

The Group has 31 debenture bond agreements outstanding, which contain provisions allowing the Group to call the debt prior to its final redemption at par if there are changes to the Norwegian tax laws or at certain specified premiums. The agreements carrying value is NOK 34,956 million at 31 December 2007 closing rate.

The Group has an agreement with an international bank syndicate for committed non-current revolving credit facility totalling USD 2.0 billion, all undrawn at 31 December 2007. The commitment fee is 0.0575 per cent per annum.

Non-current financial liabilities repayment profile

(in NOK million)	At 31 December 2007	2006
1-3 years	8,097	8,131
3-5 years	9,337	7,766
After 5 years	26,939	33,319
Total repayment of non-current financial liabilities	44,373	49,215

Non-current financial liabilities

	At 31 December 2007	2006
Non-current financial liabilities (in NOK million)	44,373	49,215
Weighted average maturity (year)	10	11
Weighted average annual interest rate	6.11%	6.23%

Current financial liabilities

(in NOK million)	At 31 December 2007	2006
Financial liabilities measured at amortised cost		
Bank loans and overdraft facilities	1,100	596
Current portion of non-current financial liabilities	1,919	2,176
Current portion of financial lease obligations	277	191
Other	2,870	2,594
Total current liabilities	6,166	5,557
Weighted interest rate	5.56%	4.85%

As of 31 December 2007 and 2006, the Group had no committed short-term credit facilities drawn.

8.1.21 Pension obligations

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 levels. 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 independent actuaries.

Some companies in the Group have defined contribution plans. The period's contributions are recognised in profit or loss as the pension cost for the period. In Norway, the Group has "agreement-based early retirement plan" (AFP) which is a defined benefit multi-employer plan. For this 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.

The obligations related to the defined benefit plans were measured at 31 December, 2007 and 2006. 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 2007 the discount rate for the defined benefit plans in Norway was estimated to be five per cent 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. StatoilHydro's opinion is 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). These are countries with similar market trends and interest levels as in Norway.

The Norwegian Standard Accounting Board (NSAB) provided guidelines on how to determine assumptions for pensions. As of 31 December 2007, NSAB's guidance suggested a discount rate of 4.5 per cent based on extrapolating the Norwegian Government bond rate by using the yield curve of Norwegian interest rate swaps. This results in a declining Norwegian yield curve. Over time, StatoilHydro believes that the Norwegian yield curve is similar to the international yield curve and is best estimated using StatoilHydro's approach. This approach is consistent with previous periods and avoids inappropriate fluctuations from one year to another.

Actuarial gains and losses are recognised directly in retained earnings in the period in which they occur, and are presented in the statement of recognised income and expense.

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. Foreign plans are insignificant and are not disclosed separately.

Net periodic pension cost

(in NOK million)	2007	2006
Current service cost	2,611	2,065
Interest cost on prior years' benefit obligation	1,713	1,421
Expected return on plan assets	(1,829)	(1,407)
Amortisation of past service cost	2,075	0
Losses (gains) from curtailment or settelment	(1,641)	0
Defined benefit plans	2,929	2,079
Defined contribution plans	160	155
Multi-employer plans	42	47
Termination benefits	8,633	49
Total net pension cost	11,764	2,330

Pension cost includes payroll tax.

StatoilHydro has made changes in the existing defined benefit plans (past service costs) due to harmonisation of the pension plans for employees in former Hydro and former Statoil. The benefits, which are already vested, amounted to NOK 2.1 billion and were recognised immediately as past service cost in 2007.

StatoilHydro ASA offered early retirement (termination benefits) to employees above the age of 58 years (contingent upon certain conditions). The expense related to termination benefits of NOK 5.6 billion and NOK 3.0 billion is recognised as Operating expenses and Selling, general and administration expenses, respectively. StatoilHydro has announced that a proportional part of the termination benefit costs will be charged to the partners in StatoilHydro operated licenses, refer to note 25. As a consequence of the early retirement scheme, StatoilHydro's existing pension obligations related to ordinary early retirement ("Avtalefestet pensjon") were reduced. The gain related to this curtailment effect was recognised in the statement of income in 2007.

The expense related to ordinary pension cost is recognised as Operating cost or Selling, general and administrative cost based on the function of the cost. Ordinary pension cost is partly charged to partners of StatoilHydro operated licences.

For information regarding pension benefits for key management personnel, refer to note 26 Related parties.

Change in projected benefit obligation (PBO)

(in NOK million)	2007	2006
Projected benefit obligation at 1 January	40,185	33,083
Current service cost	2,611	2,065
Interest cost on prior years' benefit obligation	1,713	1,421
Actuarial loss (gain)	198	4,169
Past service cost	2,075	0
Benefits paid	(605)	(481)
Curtailments	(1,641)	0
Termination benefits	8,633	0
Settlement	(329)	(63)
Foreign currency translation	(49)	(6)
Projected benefit obligation at 31 December	52,791	40,188

Change in pension plan assets

(in NOK million)	2007	2006
Fair value of plan assets at 1 January	30,110	25,624
Expected return on plan asets	1,829	1,407
Actuarial gain (loss)	(236)	1,139
Company contributions (including payroll tax)	3,777	2,301
Benefits paid	(338)	(331)
Sale of business, settlements	11	(34)
Foreign currency translation	5	4
Fair value of plan assets at 31 December	35,158	30,110

Total provision for pensions

(in NOK million)	2007	2006
Balance sheet provision at 1 January	(10,078)	(7,459)
Net periodic pension costs	(2,929)	(2,079)
Net actuarial loss (gain) recognised in the Consolidated statements of recognised income and expense	(434)	(3,030)
Less employer contributions/benefit paid during year	4,047	2,451
Settlement	340	29
Foreign currency translation	54	10
Termination benefits	(8,633)	0
Balance sheet provision at 31 December	(17,633)	(10,078)

Surplus (deficit) at 31 December:

(in NOK million)	2007	2006
Surplus (deficit) at 31 December:	(17,633)	(10,078)
Represented by:		
Asset recognised as pension asset	1,622	1,113
Liability recognised as non-current pension liability	(19,092)	(11,028)
Liability recognised as current liability	(163)	(163)

The defined benefit obligation may be analysed as follows:

(in NOK million)	2007	2006
Funded pension plans	(33,278)	(29,649)
Unfunded pension plans	(19,513)	(10,539)
PBO at 31 December	(52,791)	(40,188)

Accumulated actuarial gains and losses recognised directly in retained earnings:

(in NOK million)	2007	2006
Accumulated actuarial losses (gains) at 1 January	0	0
Actuarial losses (gains) on plan assets occured during the year	(272)	(1,139)
Actuarial losses (gains) on benefit obligaion occured during the year	198	4,169
Recognised in the Consolidated statements of recognised income and expense during the year	74	(3,030)
Accumulated actuarial losses (gains) at 31 December	0	0

Actual return on plan assets

(in NOK million)	2007	2006
Actual return on plan assets	1,593	2,546

History of experienced gains and losses:

	2007	2006
Actual return less expected return on plan assets (NOK million)	272	1,139
As % of plan assets at beginning of year	0.90%	4.45%
Experienced gains/(losses) on plan liabilities (NOK million)	(198)	(4,169)
As % of present value of plan liabilities at beginning of year	(0.49%)	(12.60%)
Total actuarial gain/(loss) (NOK million)	74	(3,030)
As % of present value of plan liabilities at beginning of year	0.25%	(9.16%)

The cumulative amount of actuarial gains and losses recognised in the statement of recognised income and expense amounted to NOK 4.2 billion net of tax (negative effect on retained earnings).

Assumptions for the year ended (Profit and Loss items) in %	2007	2006
Discount rate	4.50	4.25
Expected return on plan assets	5.75	5.75
Rate of compensation increase	4.25	3.00
Expected rate of pension increase	2.75	2.50
Expected increase of social security base amount (G-amount)	4.00	2.75
Inflation	2.25	2.25

Assumptions at end of year (Balance sheet items) in %	2007	2006
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
Inflation	2.25	2.25
Average remaining service period in years	15	15

The assumptions presented are for the Norwegian companies in the Group which are a part of StatoilHydro's pension fund. The defined benefit plans of other subsidiaries are not material to the pension assets and liabilities of the Group as a whole.

Expected turnover at 31 December 2007 was 4.0 per cent, 1.5 per cent, 1.3 per cent, 0.5 per cent and 0.0 per cent 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 2006 was 5.0 per cent, 1.3 per cent, 1.2 per cent, 0.5 per cent and 0.0 per cent 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 per cent for employees at 62 years and 30 per cent for employees at 63-66 years.

For the population in Norway, the mortality table K 2005 was used as the best estimate for mortality. 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 2007. The table shows the probability of disability or death, within one year, by age groups as well expected lifetime.

	Disability in %		Mortality in %		Expected lifetime	
Age	**Men**	**Women**	**Men**	**Women**	**Men**	**Women**
20	0.12	0.15	-	-	80.51	84.35
40	0.21	0.35	0.07	0.04	80.83	84.60
60	1.48	1.94	0.63	0.36	82.27	85.51
80	N/A	N/A	5.91	3.90	87.97	89.74

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 2007. 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 million)	**1%**	**-1%**	**1%**	**-1%**	**1%**	**-1%**	**1%**	**-1%**
Changes in pension:								
Obligation	(8,295)	11,001	6,339	(5,156)	(2,251)	2,307	6,622	(5,444)
Net periodic benefit cost	(495)	633	869	(682)	(303)	314	665	(545)

Pension assets

The plan assets related to the defined benefit plans were measured at 31 December 2007 and 2006. 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.

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

Pension assets allocated on respective investments classes

(in %)	2007	2006
Equity securities	50.50	36.00
Debt securities	31.90	44.00
Commercial papers	8.60	11.00
Real estate	6.90	5.00
Other assets	2.10	4.00
Total	100.00	100.00

Properties owned by StatoilHydro pension fund amounted to NOK 1.1 billion of total pension assets as of 31 December 2007 and are rented to companies in the Group.

StatoilHydro's pension funds invest in both financial assets and real estate. The expected rate of return on real estate is expected to be between the rate of return on equity securities and debt securities. The table below presents the portfolio weight and expected rate of return of the finance portfolio, as approved by the Board of the Statoil pension funds for 2008.

Finance portfolio StatoilHydros pension funds

(All figures in %)	Portfolio weight 1)		Expected rate of return
Equity securities	35.1	(+/- 5)	X + 4
Debt securities	55.4	(+/- 5)	X
Commercial papers	9.5	(+15/-0.5)	X -0.4
Total finance portfolio	100.0		

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.

Material company contributions are related to employees in Norway. This contribution may either be paid in cash or be deducted from the pension premium fund. On 31 December 2007, the pension premium fund amounted to NOK 7.3 billion. The decision whether to pay in cash or deduct from the pension premium fund is made on an annual basis. The company contribution in 2007, 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 for the next year amounts to NOK 2.2 billion.

8.1.22 Asset retirement obligations and other provisions

(in NOK million)	
Balance at 1 January 2006	30,570
Liabilities incurred/revision in estimates	12,082
Amounts used and charged against provision	(438)
Unused amounts reversed	0
Effects of change in the discount rate	(3,372)
Reduction due to disposals	(127)
Accretion	1,304
Currency exchange difference	(107)
Balance at 31 December 2006	39,912
Current portion of asset retirement obligations	616
Analysis of total provisions as at 31 December 2006	
Non-current portion of asset retirement obligations	39,296
Other provisions	2,877
Non-current provisions at 31 december 2006	42,173
Balance 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)
Balance at 31 December 2007	39,581
Current portion of asset retirement obligations	575
Analysis of total provisions as at 31 December 2007	
Non-current portion of asset retirement obligations	39,006
Other provisions	4,839
Non-current provisions at 31 December 2007	43,845

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, refer to note 2.

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 2007	2006
Trade payables	(21,776)	(16,122)
Non-trade payables and accrued expenses	(29,918)	(31,921)
Payables to associated companies and other related parties	(12,930)	(7,552)
Total	(64,624)	(55,595)

Non-trade payables and accrued expenses include provisions for certain claims and litigations that are further described in note 25, Other commitments and contingencies.

8.1.24 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 2007. The remaining significant contracts' terms range from three months to eight 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 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 2007, gross rental expense was NOK 7,168 million of which minimum lease payments were NOK 7,111 million and sublease payments received were NOK 1,484 million. In 2006 gross rental expense was NOK 5,853 million and sublease payments received were NOK 1,002 million.

The information in the table below shows future minimum lease payments under non-cancellable leases at 31 December 2007. In addition, StatoilHydro has entered into subleases of certain of the leased assets providing a total future rental income of NOK 5,941 million.

Amounts related to financial leases include future minimum lease payments for assets in the financial statements at year-end 2007.

		Financial lease		
(in NOK million)	Operating leases	Minimum lease payments	Interest	Principal
2008	10,892	435	15	420
2009	12,442	429	29	400
2010	10,012	401	44	357
2011	7,822	417	57	360
2012	5,344	408	59	349
Thereafter	7,844	3,649	1,525	2,124
Total future minimum lease payments	54,356	5,739	1,729	4,010

Property, plant and equipment include the following amounts for leases that have been capitalised at 31 December 2007 and 2006.

(in NOK million)	For the year ended 31 December 2007	2006
Vessels and equipment	5,503	3,227
Accumulated depreciation	(836)	(348)
Capitalised amount	4,667	2,879

8.1.25 Other commitments and contingencies

Contractual commitments

(in NOK million)	2008	2009	Thereafter	Total
Joint Venture related:				
Contractual commitments related to construction in progress	10,220	6,306	6,762	23,288
Contractual commitments related to other investments and property, plant and equipment	1,819	1,106	171	3,096
Contractual commitments related to acquisition of intangible assets	450	25	14	489
Subtotal joint venture related commitments	12,489	7,437	6,947	26,873
Non Joint Venture related:				
Contractual commitments related to construction in progress	700	92	0	792
Contractual commitments related to other investments and property, plant and equipment	26	26	81	133
Contractual commitments related to acquisition of intangible assets	6	6	0	12
Subtotal Non Joint Venture related commitments	732	124	81	937
Total	13,221	7,561	7,028	27,810

The contractual commitments mainly comprise construction and acquisition of property, plant and equipment.

StatoilHydro has entered into agreements for pipeline transportation for most of its prospective gas sales contracts. These agreements ensure the right to transport the production of gas through the pipelines, but also impose an obligation to pay for booked capacity. In addition, the Group has entered into certain obligations for other forms of transport capacity as well as terminal, processing, storage and entry capacity commitments. The following table outlines nominal minimum obligations for future years. Corresponding expenditures for 2007 and 2006 were NOK 8,900 million and NOK 8,519 million, respectively.

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 below table of contractual commitments unless they entail specific minimum payment obligations.

Obligations payable by the Group to unconsolidated equity associates are included gross in the table below. Where the Group reflects both ownership interests and transport capacity cost for a pipeline in the consolidated accounts, the amounts in the table include the net transport commitment payable for StatoilHydro.

Transport capacity and other contractual commitments at 31 December 2007:

(in NOK million)	
2008	8,500
2009	6,908
2010	6,914
2011	6,891
2012	5,993
Thereafter	37,455
Total	72,661

StatoilHydro has contractual commitments to the U.S.-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.

Guarantees
Statoil Detaljhandel has issued guarantees amounting to a total of SEK 1.1 billion (NOK 0.9 billion), the main part of which relates to financial guarantee commitments to and 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 2007 the value of the remaining volume covered by the guarantee has been estimated to a total of NOK 2,327 million at current market prices. The provision made under IAS 37 for this guarantee is immaterial at year end.

Insurance
The company 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 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 May 15, 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 2007, StatoilHydro was committed to participate in 28 wells in Norway and 41 wells outside Norway, with an average ownership interest of approximately 47 per cent. StatoilHydro's share of estimated expenditures to drill these wells amounts to approximately NOK 11 billion. Additional wells that StatoilHydro may become committed to participate in depending on future discoveries in certain licenses are not included in these numbers.

The Petrocedeño project (former Sincor project) involves the exploitation of extra heavy crude oil from the reservoirs in the Orinoco Belt. In 2007, the Decree-Law 5.200 for Migration mandated the transformation of Sincor and other oil projects into incorporated joint ventures with minimum majority participation by the Venezuelan state of 60%. As a result, our participation in Sincor has been reduced from 15% to 9.677% with effect after year end 2007. The agreed terms and conditions also include compensation for dilution of participating interest. The remaining interest in Sincor will continue to be reflected in the Consolidated Financial Statements under the equity method as StatoilHydro will have significant influence over the new company.

The new company will be known as Petrocedeño, S.A and was incorporated in late 2007. In early January 2008, Perocedeño was authorized to undertake oil activities, including upgrading extra heavy oil and will therefore conduct the operations of Sincor.

The lenders to the former Sincor project have agreed to become lenders to Petrocendeño S.A. The restructured financing became effective on 18 March 2008.

A group of Norwegian pensioners has brought legal proceedings against StatoilHydro ASA over certain changes made to the pension fund articles of association in 2002, relating to the basis for adjustment of pension payments after that date. Stavanger District Court ruled in favour of StatoilHydro in the first quarter of 2007. The Gulating Court of Appeal ruled in favour of the pensioners in the fourth quarter of 2007. The verdict has been appealed to the Supreme Court by StatoilHydro on 28 December 2007. The accounting effect of an ultimately adverse verdict for StatoilHydro has been estimated at approximately NOK 3 billion before tax.

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. The MPE has indicated that a claim will be presented based on the declaration.

The price review of two long-term natural gas contracts are currently in arbitration. Contractual price for a total volume of 6.2 billion cubic meters of gas delivered as of 31 December 2007 and for future deliveries under these contracts may be positively or negatively affected by the arbitration verdict, the final outcome of which cannot be determined at this time.

StatoilHydro ASA has decided to offer early retirement packages to employees above the age of 58 years (contingent upon certain conditions). The offer is divided in two phases, employees working onshore (first phase) and employees working offshore and on onshore plants and terminals (second phase). StatoilHydro has announced that a proportional part of these costs will be charged to the partners in StatoilHydro operated licences. The receivable (contingent asset) related to first phase is approximately NOK 2 billion, whereas the receivable related to the second phase is currently not determined.

StatoilHydro was informed on 26 September 2007 of possible consultancy agreements and transactions associated with Hydro's operations in Libya that could be in conflict with applicable Norwegian and US anti-corruption legislation. Hydro's petroleums activities in Libya were transferred to StatoilHydro as of 1 October 2007 as part of the merger with Hydro's petroleum business. Following a preliminary assessment by StatoilHydro's corporate audit function, Chief Executive Helge Lund resolved in consultation with the StatoilHydro board to initiate an external review of the relevant aspects. The purpose is to determine the facts relevant to applicable Norwegian and US anti-corruption legislation to which StatoilHydro may be subject as a result of those operations. The US law firm Sidley Austin LLP is in the process of carrying out the review together with Norwegian law firm Simonsen Advokatfirma DA, supported by StatoilHydro's corporate audit function. Other consultancy agreements relating to Hydro's international petroleum operations will also be reviewed. Both Hydro and StatoilHydro are cooperating on securing the documentation and information required to establish the facts of the matter.

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.

8.1.26 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 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 98,498 million, (237 million barrels oil equivalents) and NOK 104,628 million (254 million barrels oil equivalents) in 2007 and 2006, respectively. Purchases of natural gas from the Norwegian State (excluding purchases from licenses) amounted to NOK 287 million and NOK 293 million in 2007 and 2006, respectively. Amounts payable to the Norwegian State for these purchases are included in Accounts payable - see note 23 .

StatoilHydro is, in its own name, but for the Norwegian State's account and risk, selling the State's natural gas production. These sales, 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)	2007	2006
Current benefits	44,463,395	41,601,519
Post-employment benefits	17,414,247	13,938,077
Other non-current benefits	110,778	135,080
Share-based payment benefits	94,015	39,788

Loans to key management total less than NOK 0.4 million.

8.1.27 Financial risk management

General information relevant to risks

StatoilHydro's 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. Overall risk management means that StatoilHydro:

- has a risk and reward focus at all levels in the organisation
- evaluates significant risk exposure related to major commitments
- manages and coordinates risk at corporate level

StatoilHydro divides risk management into three categories

(1) 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.
(2) Tactical risks which are short-term trading risks based on underlying exposures managed by our principle business segment line managers, and
(3) Insurable risks which 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).

StatoilHydro's activities expose it to various financial risks: market risk (including interest rate risk, currency risk, equity price risk, and commodity price risk), liquidity risk, and credit risk.

In 2007, StatoilHydro merged with Hydro Petroleum and as a result assumed various financial risks previously managed according to Hydro Petroleum's risk management objectives, policies and procedures. StatoilHydro's and Hydro Petroleum's management of these types of financial risks may have been different however StatoilHydro is not aware of significant differences for the periods presented. Effective 1 October 2007, all financial instruments and risks are managed in accordance with StatoilHydro's risk management objectives, policies and procedures.

Market risk management

StatoilHydro operates in the worldwide crude oil, refined products, natural gas, and electricity markets and is 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 on a long and short term basis, with focus on what is best for StatoilHydro in order to achieve optimal risk adjusted returns.

StatoilHydro has established an Enterprise-Wide Risk Management Program, which establishes guidelines for entering into contractual arrangements (derivatives) to manage its commodity price, foreign currency rate, and interest rate risk. Within the program, StatoilHydro has developed a comprehensive model, which encompasses our most significant market and operational risks and takes into account correlation, different tax regimes, capital allocation on various levels and value at risk, or VaR, figures on different levels, with the goal of optimising risk adjusted return.

StatoilHydro has used and intends to use financial and commodity-based derivatives to manage the risks in overall earnings and cash flows. StatoilHydro uses swaps, options, futures, and forwards to manage its exposure to changes in the value of future cash flows primarily from future purchases and sales of crude oil and refined oil products. The term of the oil and refined oil products derivatives is usually less than one year. Natural gas and electricity swaps, options, forwards, and futures are likewise utilised to manage StatoilHydro's exposure to changes in the value of future sales of natural gas and electricity. These derivatives usually have terms of approximately three years or less. Swaps are used by StatoilHydro to manage interest rate risk related to our long-term debt portfolio.

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 minimise the commodities price volatility and match costs with revenues, 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 International Petroleum Exchange (IPE) 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 IPE.

Currency and interest rate risk
We are subject to foreign exchange and interest rate risk which are assessed on a portfolio basis in accordance with approved strategies and mandates. In market risk management and in trading, we use only well-understood, conventional derivative instruments. These include futures and options traded on regulated exchanges, OTC swaps, options and forward contracts.

Fluctuations in exchange rates can have significant effects on our results. Our cash inflows are largely denominated in or driven by U.S. dollars while our cash outflows, such as operating expenses and taxes payable, are to a large extent in NOK. Accordingly, our exposure to foreign currency rates exists primarily with U.S. dollars versus NOK. We seek to manage this currency mismatch by issuing or swapping non-current financial debt into U.S. dollars.

The existence of assets earning and liabilities owing variable rates of interest expose us to the risk of 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 funding costs 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.

Interest rate management
We principally manage our interest rates on the basis that the non-current debt portfolio shall have 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 shall be between 0 and 0.5 per cent. Exceptions can from time to time be approved if justified by factors such as corporate risk considerations, tax considerations, large non-recurring transactions, credit rating concerns, etc.

Liquidity risk management
The purpose of liquidity management and short term funding is to make certain that StatoilHydro at all times has sufficient funds available to cover financial obligations.

StatoilHydro's business activities often generate, on a monthly basis, a positive cashflow from operations. However, in months when taxes are paid (April and October) or annual dividend is paid (typically in May/June) cashflows are typically limited.

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 programs or under documentation established ad hoc. These funding programs are as follows:

- A USD 2 billion US commercial paper programme. This is the most flexible program which is 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 program.
- 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 shall maintain a minimum liquidity reserve.

Liquid assets as at 31 December

(in NOK million)	2007	2006
Cash and cash equivalents	18.3	7.5
Financial investments	3.3	1.0
Total liquid assets	21.6	8.5

Funding and liability management
As a basic principle StatoilHydro separates 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.

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

StatoilHydro has credit ratings from Moody's and Standard & Poor's. The stated objective is to have a credit 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.

In order to control StatoilHydro's refinancing risk the maturity and redemption profile of non-current debt issued shall be 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 indicates that the non-compliance is likely 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 Notes to financial statements 20, Financial liabilities.

Credit risk management
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 7.5 billion in 2007 and NOK 6.9 billion in 2006), derivative financial instruments, financial receivables, trade and other receivables, and cash and cash equivalents. StatoilHydro attempts to significantly reduce this exposure through its credit risk management policies and procedures.

StatoilHydro manages credit risk concentration with respect to financial instruments by holding only investment grade securities distributed among a variety of selected issuers. A list of authorised investment limits by commercial issuer is maintained and reviewed regularly along with guidelines which include an assessment of the financial position of counter-parties as well as requirements for collateral.

Credit risk related to commodity-based instruments is managed by maintaining, reviewing and updating lists of authorised counter-parties by assessing their financial position. StatoilHydro frequently monitors credit exposure for each counter-party, establishes internal credit lines for the counterparty, and requires collateral or guarantees when appropriate under contracts and as required by internal policies. Collateral will typically be in the form of cash or bank guarantees from highly rated international banks.

Credit risk related to interest rate swaps and currency swaps, which are OTC transactions, is derived from the counter-parties to these transactions. Counter-parties are highly rated financial institutions. The credit ratings are at a minimum reviewed annually and counter-party exposure is monitored on a continuous basis to ensure exposure does not exceed credit lines and complies with internal policies. Non-debt-related foreign currency swaps usually have terms of less than one year, and the terms of debt-related-interest swaps and currency swaps are up to 22 years, in line with that of corresponding hedged or risk managed non-current debenture bonds or bank loans.

The credit risk concentration with respect to receivables is limited due to the large number of counter-parties spread worldwide in numerous industries.

The following table contains the fair market value of open non-exchange traded derivative assets split by our assessment of the counter-party's credit risk:

(in NOK million)	At 31 December 2007	2006
Counter-party rated:		
Investment grade, rated A or above	19,647	17,326
Other investment grade	928	1,805
Non-investment grade or not rated	689	416

As of 31 December 2007, NOK 2.8 billion in collateral is available to the Group to offset a portion of this credit exposure.

Credit rating categories in the table above are based on the Group's internal credit rating policies, and do not always correspond directly with ratings issued by the major credit rating agencies due to internal evaluation criteria. Consistent with StatoilHydro 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.

8.1.28 Financial instruments by category

Fair values of financial instruments by category
The tables below provide a comparison of carrying amounts and fair values of all the Group's financial instruments including derivative financial instruments.

			Fair value through profit or loss			
(in NOK million)	Loans and receivables	Available-for-sale	Held for trading	Fair value option	Total carrying amount	Fair value
31 December 2007						
Assets as per balance sheet						
Non-current financial investments	0	3,291	0	11,975	15,266	15,266
Non-current derivative financial instruments	0	0	609	0	609	609
Non-current financial receivables	3,515	0	0	0	3,515	3,515
Current trade and other receivables	69,378	0	0	0	69,378	69,378
Current derivative financial instruments	0	0	21,093	0	21,093	21,093
Current financial investments	0	0	3,359	0	3,359	3,359
Cash and cash equivalents	18,264	0	0	0	18,264	18,264
Total	91,157	3,291	25,061	11,975	131,484	131,484

			Fair value through profit or loss			
(in NOK million)	Loans and receivables	Available-for-sale	Held for trading	Fair value option	Total carrying amount	Fair value
31 December 2006						
Assets as per balance sheet						
Non-current financial investments	0	2,262	0	11,750	14,012	14,012
Non-current derivative financial instruments	0	0	450	0	450	450
Non-current financial receivables	4,341	0	0	0	4,341	4,341
Current trade and other receivables	81,046	0	0	0	81,046	81,046
Current derivative financial instruments	0	0	21,323	0	21,323	21,323
Current financial investments	0	0	1,032	0	1,032	1,032
Cash and cash equivalents	7,518	0	0	0	7,518	7,518
Total	92,905	2,262	22,805	11,750	129,722	129,722

Financial assets are measured at fair value or their carrying amounts reasonably approximate fair value. See note 2, Significant accounting policies, and note 29, Financial instruments and hedging activities, for further information regarding measurement of fair values.

(in NOK million)	Amortised cost	Fair value through profit or loss	Total carrying amount	Fair value
31 December 2007				
Liabilities as per balance sheet				
Non-current financial liabilities	44,373	0	44,373	47,278
Non-current derivative financial instruments	0	1	1	1
Current trade and other payables	64,624	0	64,624	64,624
Current financial liabilities	6,166	0	6,166	6,166
Current derivative financial instruments	0	7,632	7,632	7,632
Total	**115,163**	**7,633**	**122,796**	**125,701**
31 December 2006				
Liabilities as per balance sheet				
Non-current financial liabilities	49,215	0	49,215	53,014
Non-current financial instruments	0	66	66	66
Current trade and other payables	55,595	0	55,595	55,595
Current financial liabilities	5,557	0	5,557	5,557
Current derivative financial instruments	0	6,549	6,549	6,549
Total	**110,367**	**6,615**	**116,982**	**120,781**

Financial liabilities' carrying amounts reasonably approximate fair value except the fair values of non-current financial liabilities which have been determined by using year-end market interest rates to calculate discounted cashflows. See note 2, Significant accounting policies, and note 29, Financial instruments and hedging activities, for further information regarding measurement of fair values.

The following table includes amounts from the Statement of income related to financial instruments.

	Fair value through profit or loss			
(in NOK million)	Held for trading	Fair value option	Instruments at amortised cost	Available-for-sale assets
For the year ended 31 December 2007				
Net gains	0	0	0	129
Net losses	(1,689)	(263)	(245)	0
Total interest income	202	351	1,941	308
Total interest expense	0	0	(3,084)	0
Total	(1,487)	88	(1,388)	437
For the year ended 31 December 2006				
Net gains	5,577	620	412	0
Net losses	0	0	0	0
Total interest income	590	332	1,801	244
Total interest expense	0	0	(1,658)	0
Total	6,167	952	555	244

Dividend income is included with Total interest income. Foreign exchange gains or losses related to financial instruments are not included, see note 8, financial items, for additional information.

8.1.29 Financial instruments and hedging activities

Fair value hedges
Fair value hedges are hedges of StatoilHydro's exposure to changes in the fair value of a recognised asset and liability or an unrecognised firm commitment. StatoilHydro has designated certain interest rate swaps as fair value hedges to hedge against changes in the fair value, due to changes in the interest rates, of certain parts of the Group's financial liabilities. There was no significant element of hedge ineffectiveness the year ended 31 December 2007. 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 risk of bonds subject to hedge accounting are presented below together with the related gains and losses.

(in NOK million)	Fair value	Gains (losses)
At 31 December 2007		
Hedging instruments	651	221
Hedged risk of bonds subject to hedge accounting	(724)	(212)
At 31 December 2006		
Hedging instruments	430	(459)
Hedged risk of bonds subject to hedge accounting	(512)	452

Fair value of derivative financial instruments and fixed rate interest bearing bonds

The Group recognises all derivative financial instruments in the balance sheet at fair value. Changes in the fair value of derivatives are included in the Statement of income either in revenue or in financial items. In some instances the carrying amount is assessed to be a reasonable approximation of fair value, the instrument is then recognised in the balance sheet at the carrying amount. For StatoilHydro this is the case for current trade receivables and payables. For more information about the methodology and assumption used when calculating the fair value of the financial instruments see note 2, Significant accounting policies.

The following table contains the carrying amounts and estimated fair values of derivative financial instruments including certain derivative commodity contracts, and the carrying amounts and estimated fair value of fixed rate interest bearing bonds. Commodity contracts capable of being settled by physical delivery of commodities (crude oil, refined products, natural gas and electricity) are excluded from the summary. Of the total ending balance at 31 December 2007 NOK 9.6 billion relates to certain earn-out agreements recognised as derivative financial instruments in accordance with IAS 39. At the end of 2006 NOK 6.7 billion was related to these agreements.

(in NOK million)	Fair value of assets	Fair value of liabilities	Net carrying amount
At 31 December 2007			
Debt-related instruments	4,676	(125)	4,551
Non-debt-related instruments	1,802	(163)	1,639
Non-current fixed interest liabilities	0	(38,971)	(35,923)
Crude oil and Refined products	10,620	(1,446)	9,174
Gas and Electricity	599	(795)	(196)
At 31 December 2006			
Debt-related instruments	3,972	(413)	3,559
Non-debt-related instruments	2,057	(338)	1,719
Non-current fixed interest liabilities	0	(46,166)	(42,338)
Crude oil and Refined products	7,462	(681)	6,781
Gas and Electricity	1,646	(273)	1,373

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 27, 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 for 2007 and 2006 has been calculated by assuming a hypothetical across-the-board 10% change in all commodity prices. This does not take into account the term or historical relationships between the contractual price of the instrument and the underlying commodity prices or the expected correlation between risk categories. Therefore, in the event of an actual 10% change in all underlying prices, the change in the fair value of the derivative portfolio at the two respective year ends would typically be different from that shown below. In addition, there would be expected offsetting effects from changes in the fair value of our corresponding physical positions, contracts and anticipated transactions, which are not recorded at fair value, and are not reflected in the below table.

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

(in NOK million)	Fair value asset	Fair value liability	-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)

Where an active market exists, financial instruments are valued on the the basis of quoted information from the active market. The following table summarises the basis for fair value estimation and the maturity of such 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 2007					
Fair value based on prices quoted in an active market	906	1,731	178	2,108	4,923
Fair value based on price inputs from external sources	5	7	0	0	12
Fair value based on inputs from other sources	13	(1)	(1)	9,854	9,865
At 31 December 2006					
Fair value based on prices quoted in an active market	4,073	1,057	1,498	1,011	7,639
Fair value based on price inputs from external sources	239	278	0	(1,069)	(552)
Fair value based on inputs from other sources	59	217	(10)	7,666	7,932

Even though the major part of the fair value from certain earn out agreements are from observable external sources 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 price. When extrapolating the forward curve with inflation the fair value of the contracts included will increase by approximately NOK 2.5 billion. This increased change in fair value would be recognised in the Statement 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 above. Changes in the fair value of commodity-based financial instruments due to different assumptions made on future exchange rates and interest rates is deemed immaterial. See however text below under Interest and currency risk for details of aggregate effects of such sensitivities.

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 27, Financial risk management.

(in NOK million)	2007	2006
Less than 1 year	(5,279)	(4,575)
1 - 3 years	(2,094)	(1,815)
4 - 5 years	(113)	(98)
After 5 years	(147)	(127)
Derivative financial instruments	(7,633)	(6,615)

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 fair value of financial instruments related to our interest rate swaps, currency swaps and fixed interest non-current liabilities are specified in the table below:

(in NOK million)	Net fair value
At 31 December 2007	
Debt-related instruments	4,551
Non-debt related instruments	1,639
Non-current fixed interest liabilities	(38,971)
At 31 December 2006	
Debt-related instruments	3,559
Non-debt related instruments	1,719
Non-current fixed interest liabilities	(46,166)

The estimated loss that would be recognised in the Statement of income associated with a 10% adverse change in NOK currency rates would be approximately NOK 10.4 billion and NOK 7.6 billion as of 31 December, 2007 and 2006, respectively. A hypothetical one percentage point adverse change in interest rates would result in a loss, that would be recognised in the income statement, of NOK 2.7 billion and NOK 2.4 billion related to interest-bearing liabilities, investments in debt securities and related financial instruments as of 31 December, 2007 and 2006, respectively. These estimated currency and interest rate sensitivities are based on an uncorrelated loss scenario and actual results could vary due to assumptions used and because offsetting account correlations are not reflected within this analysis. All financial instruments included in the interest and currency rate sensitivity calculation have a linear sensitivity towards changes. Therefore a positive change in the NOK currency rates and interest rates would give a gain that would be recognised in the Statement of income, with the opposite values as the losses calculated for the negative changes.

StatoilHydro's cash flows are largely in US dollars, European euro and Norwegian kroner, but significant amounts are also Swedish kroner, Danish kroner and UK pounds sterling. The currencies in the debt portfolio are managed in connection with our expected future net cash flows per currency. The Group's debt, after considering currency swaps, is mainly in US dollars.

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-marketable 0-20% investments classified as Available for sale investments in accordance with IAS 39. These are recognised at fair value in the balance sheet with changes in the fair value recognised directly in equity.

Risk is estimated as the potential loss in fair value resulting from a hypothetical 10% adverse change in quoted market prices. Actual results may vary due to assumptions utilised and because correlation are not reflected within the analysis.

(in NOK million)	Fair value	-10% sensitivity	10% sensitivity
At 31 December 2007			
Fair value of marketable equity securities	4,230	(423)	423
Fair value of other non-marketable equity securities	3,291	(329)	329
At 31 December 2006			
Fair value of marketable equity securities	4,600	(460)	460
Fair value of other non-marketable equity securities	2,262	(226)	226

8.1.30 Subsequent events

On 4 March 2008 StatoilHydro and Anadarko signed an agreement whereby StatoilHydro will take over the remaining 50% in the Brazilian Peregrino project and 25% of the Kaskida discovery in US Gulf of Mexico. The initial 50% of Pergrino was purchased by StatoilHydro in 2006 for USD 368 million. The final transaction will provide StatoilHydro with a 100% working interest and operatorship of the development in the Peregrino project. For the last 50% interest in the Pergrino project and 25% in the Kaskida discovery StatoilHydro will pay Anadarko USD 1.8 billion, plus a maximum pre-tax earn-out of USD 300 million payable by 2020, conditional on future oil prices above pre-defined threshold levels. The transaction is pending governmental approval. The other partners pre-emption rights on Kaskida is expected to be executed.

On 1 March 2008 Sonatrach and StatoilHydro signed an agreement for long-term arrangement at the Cove Point liquefied natural gas (LNG) terminal in the USA. Under the terms of the contract, Sonatrach will receive access to an annual two billion cubic metres of regasification capacity at the Cove Point terminal for 15 years from the beginning of 2009. As part of the arrangement, StatoilHydro will also purchase 1 billion cubic metres of LNG per year from Sonatrach at Cove Point from 2009 to 2014. The terms and conditions governing the arrangement have been agreed in the form of binding Heads of Agreements (HOAs).

8.1.31 IFRS transition

The accounting policies set out in note 2 have been applied in preparing the financial statements for the year ended 31 December 2007, the comparative information presented in these financial statements for the year ended 31 December 2006 and the preparation of an opening IFRS balance sheet at 1 January 2006 (the Group's date of transition).

Reconciliation of shareholders' equity as at 1 January 2006 and 31 December 2006 and the Consolidated net income for 2006

Reconciliation of shareholders' equity as at 1 January 2006 and 31 December 2006 and the Consolidated net income for 2006

(in NOK million)	For the year ended 31 December 2006
Hydro Petroleum consolidated net income under US GAAP	10,384
Former Statoil Group consolidated net income under US GAAP (including minority interest)	41,335
Merger adjustments	(78)
Differences related to:	
Financial instruments	3,108
Inventory valuation	(321)
Deferred tax adjustments	(2,369)
Other	(212)
Net changes	206
Consolidated net income for the period under IFRS	51,847

(in NOK million)	At 1 January 2006	At 31 December 2006
Hydro Petroleum US GAAP Equity	36,399	33,071
Former Statoil Group US GAAP Equity (including minority interest)	108,136	123,693
Merger adjustments	12,680	10,027
Differences related to:		
Financial instruments	4,420	7,715
Pensions	(8,712)	(2,948)
Inventory valuation	2,820	2,499
Asset retirement obligations (ARO)	(3,167)	(2,976)
Deferred tax adjustments	861	(3,248)
Other	2,945	1,574
Net changes	(832)	2,616
Total equity under IFRS	156,384	169,407

Under US GAAP, former Statoil and Hydro Petroleum would not have been reflected as a combined entity in 2006. The US GAAP figures for former Statoil and Hydro Petroleum and the merger related adjustments have been combined for illustrative purposes only to show how the transition to IFRS impacted the two companies in the tables that follow.

Impact on cash flow statement

The Group continues using the indirect method when preparing the statement of cash flows under IFRS as it used to do under the previous US GAAP. Consequently, adjustments made to working capital items in the balance sheet on transition to IFRS lead to an adjustment in the IFRS statement of cash flows. There are no significant changes between cash flows from operating activities, investing activities, and financing activities. No adjustments have been made to cash and cash equivalents, and no other adjustments have been made to the statements of cash flows on conversion.

Opening IFRS balance sheet

In preparing its opening IFRS balance sheet as at 1 January 2006, the group has adjusted amounts reported previously in financial statements prepared in accordance with its old basis of accounting, US GAAP. An explanation of how the transition from US GAAP to IFRS has affected the Group's statement of income, balance sheet ands statement of cash flows is set out below.

IFRS 1 EXEMPTIONS AND ELECTIONS APPLIED AND IAS 1 PRESENTATION

The Group applied IFRS 1, *First-time Adoption of International Financial Reporting Standards* in making the transition to IFRS, with 1 January 2006 as the date of transition to IFRS. IFRS 1 requires that all IFRS standards and interpretations are applied consistently and retrospectively for all fiscal years presented. However, this standard provides exemptions and exceptions to this general requirement in specific cases. The Group has chosen to apply the following exemptions:

Business Combinations

Business combinations that occurred before 1 January 2006, were not restated retrospectively in accordance with IFRS 3, *Business Combinations*. Within the limits imposed by IFRS 1, the carrying amounts of assets acquired and liabilities assumed as part of past business combinations as well as the amounts of goodwill that arose from such transactions as they were determined under US GAAP, are considered their deemed cost under IFRS at the date of transition.

Cumulative currency translation differences

Cumulative currency translation differences as of 1 January 2006, arising from translation into NOK of the financial statements of foreign operations whose functional currency is not the NOK were reset to zero. Accordingly, the cumulative translation differences were included in *Retained earnings* in the IFRS opening balance sheet. In the case of subsequent disposal of an entity concerned, no amount of currency translation difference relating to the time prior to the translation date will be included in the determination of the gain or loss on disposal of such entity.

Decommissioning liabilities included in the cost of property, plant and equipment

IFRIC 1 *Changes in Existing Decommissioning Restoration and Similar Liabilities* requires changes in a decommissioning liability to be added or deducted from the cost of the asset to which it relates. IFRS 1 allows a first time adopter to not comply with this requirement for changes in such liabilities that occurred before the date of transition to IFRS. The Group has used this exemption and has measured the liability at the date of transition in accordance with IAS 37, estimated the amount that would have been included in the asset, and calculated the accumulated depreciation on that amount, on the basis of the current estimate of the useful life of the asset.

Changes in presentation of the consolidated financial statements

The presentation of the consolidated financial statements has been modified to comply with the requirements of IAS 1, *Presentation of Financial Statements*. As a result of applying the new option provided by IAS 19 to recognise actuarial gains and losses directly in equity, consolidated statements of income and expense recognised in equity have been included. Under IFRS minority interests are presented within equity.

Restatement of Consolidated Statement of Income for 2006 from US GAAP to IFRS

	StatoilHydro group			
	Former Statoil and Hydro Petroleum as if previously reported combined - US GAAP	**IFRS reclassifications**	**IFRS adjustments**	**IFRS**
	For the year ended 31 December			
(in NOK million)	**2006**			**2006**
Total revenues and other income	509,952	7,257	4,273	521,482
Cost of goods sold	(242,586)	(5,627)	(1,381)	(249,593)
Operating expenses	(45,874)	1,270	(198)	(44,801)
Selling, general, and administrative expenses	(9,525)	(1,126)	(174)	(10,824)
Depreciation, amortisation and impairment losses	(39,511)	(11)	72	(39,450)
Exploration expenses	(10,650)	-	-	(10,650)
Total operating expenses	(348,144)	(5,494)	(1,680)	(355,319)
Net operating income	161,808	1,763	2,593	166,164
Net financial items	6,706	(1,618)	(16)	5,072
Income before tax	168,514	145	2,577	171,236
Income tax	(116,872)	(145)	(2,372)	(119,389)
Net income	51,642	0	206	51,847

Restatement of Consolidated Balance Sheet as at 1 January and 31 December 2006 from US GAAP to IFRS

US GAAP on IFRS format	Former Statoil and Hydro Petroleum as if previously reported combined - US GAAP 1 Jan 2006	IFRS reclassifications	IFRS adjustments	IFRS 1 Jan 2006
ASSETS				
Non-current assets				
Property, plant, and equipment	273,574	(18,494)	313	255,393
Intangible assets	5,164	19,544	196	24,904
Equity accounted investments	8,830	(260)	69	8,638
Deferred tax assets	4,538	(3,733)	0	805
Pension assets	6,810	0	(4,696)	2,114
Non-current financial investments	11,572	31	1,969	13,572
Derivative financial instruments	0	835	0	835
Non-current financial receivables	5,105	73	0	5,178
Total non-current assets	315,593	(2,004)	(2,149)	311,439
Current assets				
Inventories	9,683	266	2,702	12,651
Trade and Other receivables	86,658	(1,281)	0	85,377
Derivative financial instruments	5,799	(531)	6,749	12,018
Current financial investments	6,847	0	0	6,847
Cash and cash equivalents	7,436	0	0	7,436
Total current assets	116,423	(1,546)	9,451	124,328
TOTAL ASSETS	432,016	(3,550)	7,302	435,767
EQUITY AND LIABILITIES				
Total equity	157,216	0	(832)	156,384
Non-current liabilities				
Non-current financial liabilities	53,094	0	(342)	52,752
Deferred tax liabilities	74,722	(3,756)	(861)	70,105
Pension liabilities	6,002	0	3,930	9,932
Non-current provisions	30,508	45	2,337	32,889
Derivative financial instruments	0	113	0	113
Total non-current liabilities	164,326	(3,598)	5,063	165,791
Current liabilities				
Trade and other payables	59,836	(141)	0	59,695
Income taxes payable	42,486	(2)	0	42,484
Current financial liabilities	1,718	0	0	1,718
Derivative financial instruments	6,432	191	3,071	9,694
Total current liabilities	110,474	48	3,071	113,592
Total liabilities	274,800	(3,550)	8,134	279,383
TOTAL EQUITY AND LIABILITIES	432,016	(3,550)	7,302	435,767

US GAAP on IFRS format	Former Statoil and Hydro Petroleum as if previously reported combined - US GAAP 31 Dec 2006	IFRS reclassifications	IFRS adjustments	IFRS 31 Dec 2006
ASSETS				
Non-current assets				
Property, plant, and equipment	302,783	(27,251)	(3,369)	272,163
Intangible assets	5,108	27,706	(1,609)	31,205
Equity accounted investments	8,945	(475)	86	8,556
Deferred tax assets	2,457	(1,876)	227	808
Pension assets	3,314	0	(2,201)	1,113
Non-current financial investments	12,680	0	1,332	14,012
Derivative financial instruments	0	450	0-	450
Non-current financial receivables	4,341	0	0	4,341
Total non-current assets	339,629	(1,446)	(5,535)	332,648
Current assets				
Inventories	12,758	0	2,499	15,256
Trade and Other receivables	81,046	0	0	81,046
Derivative financial instruments	12,010	1,552	7,761	21,323
Current financial investments	1,032	0	0	1,032
Cash and cash equivalents	7,518	0	0	7,518
Total current assets	114,363	1,552	10,260	126,175
TOTAL ASSETS	453,992	106	4,725	458,823
EQUITY AND LIABILITIES				
Total equity	166,791	0	2,616	169,407
Non-current liabilities				
Non-current financial liabilities	49,520	0	(305)	49,215
Deferred tax liabilities	72,335	(1,936)	1,685	72,084
Pension liabilities	10,281	0	747	11,028
Non-current provisions	43,302	40	(1,170)	42,173
Derivative financial instruments	0	66	0	66
Total non-current liabilities	175,439	(1,830)	957	174,566
Current liabilities				
Trade and other payables	55,221	0	374	55,595
Income taxes payable	47,149	0	0	47,149
Current financial liabilities	5,557	0	0	5,557
Derivative financial instruments	3,835	1,936	779	6,549
Total current liabilities	111,761	1,936	1,153	114,850
Total liabilities	287,200	106	2,109	289,416
TOTAL EQUITY AND LIABILITIES	453,992	106	4,725	458,823

DESCRIPTION OF PRIMARY CHANGES IN ACCOUNTING POLICIES

Derivative financial instruments and hedge accounting

The Group is party to a number of contractual agreements, such as earn-out agreements and long-term sales agreements, which are linked to underlying indices. These agreements are not accounted for as fair value derivatives under US GAAP due to specific exemption rules in FAS 133 and related interpretations, whereas certain agreements are accounted for as fair value derivatives under IFRS. This treatment under IFRS requires that the contracts are carried at fair value in the balance sheet, with changes in fair value being recorded in the statement of income.

Both US GAAP and IFRS allow hedge accounting to be used when specific criteria are met. There are differences in certain of these criteria between US GAAP and IFRS and as a result, certain hedging transactions that can be hedge accounted under US GAAP, do not qualify for hedge accounting under IFRS, and vice versa.

Under US GAAP a number of fair value hedges are accounted for using the short-cut method meaning that any ineffectiveness is not recognised in the statement of income. The same items and instruments are also accounted for as fair value hedges under IFRS, which requires that any ineffectiveness is calculated and recorded in the statement of income, resulting in a GAAP difference.

In accordance with specific FAS 133 transition provisions, one hedging relationship involving part of a bond hedged with cross currency interest rate swaps is accounted for as a hedge relationship under US GAAP. Due to the specifics of this particular relationship and lack of similar transition provisions, hedge accounting is not permissible under IFRS. Consequently, the bond is carried at amortised cost while the associated interest rate swaps are carried at fair value with changes being reported in the statement of income.

Pensions

The Group IFRS accounting policy is to recognise actuarial gains and losses in respect of the group's pension and post-retirement benefit plans directly to equity via the consolidated statement of recognised income and expense. Under US GAAP (applicable until 31 December, 2006), actuarial gains and losses are deferred and recognised in future periods. Therefore a GAAP difference exists at 1 January, 2006, 31 March, 2006, 30 June, 2006, and 30 September, 2006.

During the fourth quarter of 2006, a new US GAAP standard was issued that requires cumulative actuarial gains and losses to be recognised in full in the 31 December 2006 balance sheet, with a corresponding adjustment to equity. At 31 December 2006, there continue to be GAAP differences. Under US GAAP the equity adjustment relating to actuarial gains and losses will be reversed in future periods applying the corridor approach and recorded to the statement of income, whereas under IFRS this entry is not allowed.

A remaining GAAP difference also exists in relation to the discount rate applied to the Group's pension liabilities and service costs. Under US GAAP, discount rates are set by reference to high-quality corporate bonds. IFRS specifically requires the use of government bonds in countries where there is no deep market in high-quality corporate bonds, which is the case in Norway and Sweden. As a result, the IFRS discount rates were lower than the US GAAP discount rates applied in the period, resulting in a higher pension liability being recorded.

Inventory - application of the FIFO cost method instead of LIFO

Under the Group's US GAAP policy, the cost of inventories is measured using the last-in first-out (LIFO) method. Under IFRS, inventory cost is measured on the basis of the first-in first-out (FIFO) formula.

Asset retirement obligations (ARO)

For both US GAAP and IFRS, the cost of property, plant, and equipment includes the estimated cost of dismantling and removing the asset and restoring the site to the extent that such cost is recognised as a provision. The provision is measured as the best estimate of future expense, discounted to today's value using an appropriate discount rate. Under US GAAP, the discount rate applied to an ARO obligation upon initial recognition is not changed throughout the life of the provision. For any addition to an ARO obligation, the latest discount rate is used, and then this is not revisited in future periods. Under IFRS, the discount rate applied to an ARO obligation is reviewed and updated each period.

Deferred tax

Deferred tax adjustments arise from both specific GAAP differences and from tax effects of adjustments recognised upon conversion to IFRS.

Consequential deferred tax adjustments: Nearly all recognised IFRS conversion adjustments as discussed in this transition note have related effects on deferred taxes.

Functional currency different than taxable currency: Under US GAAP, no deferred tax is recognised for differences resulting from changes in exchange rates related to non-monetary assets and liabilities that are measured in the functional currency for accounting purposes, but have a different taxable currency. Under IFRS deferred tax is recognised for differences related to non-monetary assets and liabilities that are measured in the functional currency, but have a different taxable currency.

Tax on unrealised intra-group profits: Under US GAAP, deferred tax is recognised for differences arising from intra-group transactions using the seller's tax rate. Under IFRS, deferred tax is recognised using the buyer's tax rate.
Exemptions: Under US GAAP deferred taxes are provided on virtually all temporary differences.

IFRS has an exemption from provisions to recognise deferred taxes on a transaction when the deferred tax assets/liabilities arise from the initial recognition of assets and liabilities which at the time of the transaction, affects neither accounting profit nor taxable profit.

Other adjustments
Other adjustments comprise the following:

Adjustments to property, plant and equipment (PP&E)
The most significant adjustment to PP&E relates to significant periodic maintenance programs. Under the Group's current US GAAP policy, the estimated costs of future major maintenance and inspections are accrued in advance. Under IFRS, the costs of major maintenance and inspection are included in the carrying amount of PP&E when incurred, and are depreciated over the period to the next major maintenance and inspection date.

A difference also exists for 'abnormal waste'. Under US GAAP, all costs in the construction phase are normally capitalised. Under IFRS, any costs that relate to abnormal waste are expensed.

Exchange of similar assets
In 2000 the Group swapped an ownership share in a processing plant to a third party, in exchange for receiving an ownership share in another processing plant. Under US GAAP standards applicable at that time, no gain or loss was recorded on this transaction.

Available for sale financial asset
Under US GAAP, certain investments classified as available for sale financial assets are accounted for at cost due to lack of readily determinable fair values. Under IFRS, these investments are classified as available for sale financial assets and carried at estimated fair value in the balance sheet, with changes in fair value being recorded directly to equity.

Reversal of impairment of exploration costs
Under US GAAP, certain exploration costs were expensed as impairment. Impairments are not reversed under US GAAP. Under IFRS, impairments are reversed, as applicable, to the extent that the conditions for impairment are no longer present.

Provisions
A decision was made and communicated in the fourth quarter of 2006 to implement a new business model, which included amendments and terminations of franchise agreements in Sweden. At 31 December 2006, the criteria were not met to record a provision for US GAAP purposes. Under IFRS, a provision was made at 31 December 2006 as the Group had a constructive obligation.

Reclassifications
Reclassifications comprise:

Re-inclusion of Discontinued Operations as Assets Held for Sale
Under US GAAP the Group has from January 2006 classified its Irish downstream Retail and Commercial & Industrial business (Statoil Ireland) as Held for sale in the balance sheet and as a discontinuing operation in the statement of income for all periods presented, including comparative figures.

Under IFRS, disposal groups are classified as discontinued operations where they represent a major line of business or geographical area of operations. The group has not classified Statoil Ireland as a discontinuing operation in the statement of income as it does not represent a separate major line of business or geographical area. Under IFRS, the classification as Held for sale in the balance sheet is not reclassified for periods before the assets become held for sale, whereas under US GAAP comparative figures are adjusted. The criteria for classification as held for sale were met in January 2006.

Gross versus net presentation of derivative assets and liabilities
Under US GAAP the group has applied certain options to present derivative assets and derivative liabilities on a net basis. When there is an underlying agreement to offset, but there was no initial intention to do so, derivatives have been reclassified to show gross amounts under IFRS.

Derivatives designated as hedging instruments
Under US GAAP, the fair value of derivatives designated as hedging instruments has been classified as current, in line with the classification of the Group's other derivatives. Under IFRS the non-current portion of the fair value of derivatives designated as hedging instruments has been classified as non-current assets and liabilities.

Investments accounted for using the equity method
Under US GAAP, the Group proportionately consolidated investments in jointly controlled assets held in the Exploration and Production Norway and the International Exploration and Production segments, but used equity method for jointly controlled assets in other segments. Under IFRS, all jointly controlled assets have been proportionately consolidated.

Capitalised costs before the development phase
Under US GAAP, capitalised costs before the development phase were classified as *Property, plant, and equipment*. Under IFRS, capitalised costs before the development phase were classified as *Intangible assets*.

Deferred tax assets and liabilities
Classification rules for deferred tax assets and liabilities are different under IFRS compared to US GAAP. Current deferred tax items have been reclassified to non-current assets and liabilities.

Cumulative translation differences
IFRS 1 allows for cumulative currency translation differences to be set to zero at 1 January 2006. US GAAP has no equivalent to the transition arrangements of IFRS 1.

Accretion expense
Under both US GAAP and IFRS certain liabilities are recorded in the balance sheet at a discounted amount. These liabilities will increase each year due to the unwinding of the discount, as the liability becomes one year nearer. This increase (referred to as 'accretion expense') is reported as a cost in the income statement.
Under US GAAP, the accretion expense is recorded as an operating expense. Under IFRS, the accretion expense is recorded as a finance cost.

8.1.32 Supplementary oil and gas information (UNAUDITED)

In accordance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities and regulations of the US Securities and Exchange Commission (SEC), StatoilHydro is making certain supplemental disclosures about oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, it is emphasised that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgement involved in developing such information. Accordingly, this information may not necessarily represent the present financial condition of StatoilHydro or its expected future results.

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 SEC. 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. 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.

On the Norwegian Continental Shelf, StatoilHydro sells its oil and gas together with the oil and gas of the Norwegian state (SDFI). Under this arrangement, StatoilHydro and the SDFI jointly deliver gas from Norway and elsewhere to its customers in accordance with certain supply type sales contracts. The commitments will be met by using a field supply schedule that provides the highest possible total value for the joint portfolio of StatoilHydro's and SDFI's oil and gas. Likewise, we hold commitments to deliver gas from Azerbaijan and Algeria where our entitlement to gas deliveries under the production sharing agreements is less than our commitment to deliver. Our proved gas reserves (entitlements) will be drawn on to supply this gas to the extent that we hold entitlement to the gas delivered.

The total expected commitments to be met by the StatoilHydro / SDFI arrangement and StatoilHydro's separate commitments were on 31 December, 2007 to deliver a total of 36.4 tcf. This does not include commitments where we do not hold title to the gas that we deliver.

A major part of StatoilHydro's gas volumes are sold under contracts with long term Take or Pay clauses. StatoilHydro's customers have flexibility to vary off take under the contracts on a daily basis. StatoilHydro's and SDFI's delivery commitments, are expressed as the sum of an Annual Contract Quantity (ACQ). ACQ's for the contract years 2007, 2008, 2009 and 2010 are 2.56, 2.63, 2.56 and 2.59 tcf. These commitments may be met by production of proved reserves from fields were StatoilHydro and/or the Norwegian State participates and by drawing on existing gas markets to manage temporary shortfalls or surpluses in production. We are currently in a situation with a shortfall in supply of LNG from our own production in contract year 2007 due to production problems in the start-up phase of an LNG liquefaction plant in Norway. Efforts to mitigate the effects of this are being made. This concerns approximately 2 per cent of our commitments to deliver gas in this contract year. The shortfall in supply of LNG from our own production is expected to have effect also in the contract year 2008.

The principles for booking of proved gas reserves are limited to contracted gas sales and gas with access to a market.

In 2002, StatoilHydro entered into a buy-back contract in Iran. StatoilHydro also participates in a number of production sharing agreements (PSA). 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.

The transformation process of the Sincor joint venture in Venezuela, into the new mixed company Petrocedeño was not finalised by year-end 2007. Therefore, StatoilHydro's proved reserves at 31 December 2007 include a share of 15% of reserves in the Sincor joint venture structure. StatoilHydro's shareholding interest in Petrocedeño was reduced to 9.677% in the first quarter of 2008. The change in StatoilHydro share will result in a reduction of proved reserves corresponding to 68 million barrels in 2008.

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 subtotals and totals in the following tables may not equal the sum of the amounts shown due to rounding.

	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	0	433	433	0	973	973	0	606	606
Production from PSA and buy-back agreements	0	46	46	0	83	83	0	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	0	0	0	0	0	0	0	0	0
Sales of reserves-in-place	0	(2)	(3)	0	0	0	0	(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	0	441	441	0	1,169	1,169	0	649	649
Production from PSA and buy-back agreements	0	47	47	0	56	56	0	57	57
Revisions and improved recovery	197	16	214	598	(27)	571	311	14	325
Extensions and discoveries	38	105	143	405	0	405	110	105	215
Purchase of reserves-in-place	0	0	0	0	0	0	0	0	0
Sales of reserves-in-place	0	0	0	0	0	0	0	0	0
Production	(299)	(92)	(391)	(1,238)	(114)	(1,352)	(519)	(112)	(632)
At 31 December 2007	1,604	785	2,389	18,893	1,426	20,319	4,971	1,039	6,010
Of which:									
Proved developed reserves	1,187	323	1,510	15,084	748	15,832	3,875	456	4,331
Proved reserves under PSA and buy-back agreements	0	387	387	0	977	977	0	561	561
Production from PSA and buy-back agreements	0	67	67	0	80	80	0	82	82

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 and 1,000 standard cubic meter gas = 1 standard cubic meter oil equivalent.

StatoilHydro is required through its articles of association to market and sell the SDFI's oil and gas together with StatoilHydro's own oil and gas in accordance with the owner's instruction established by the general meeting of StatoilHydro ASA. SDFI and StatoilHydro receive income from the joint natural gas sales portfolio based on their respective share in the supply volumes. For sale of natural gas to third parties or to StatoilHydro for further value upgrade the pricing is either: achieved prices, a net back formula or market value. For natural gas acquired by StatoilHydro for its own use the pricing will be based on market value. All of the Norwegian State's oil and NGL will be acquired by StatoilHydro. Pricing of the crude oil will be based on market reflective prices; NGL prices will be 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.

Capitalised expenditures related to Oil and Gas producing activities

	At 31 December	
(in NOK million)	**2007**	**2006**
Unproved Properties	40,511	26,096
Proved Properties, wells, plants and other equipment	548,614	501,472
Total Capitalised expenditures	589,125	527,568
Accumulated depreciation, depletion, amortisation and valuation allowances	(331,653)	(283,428)
Net Capitalised expenditures	257,472	244,140

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 2007			
Exploration Costs	5,749	8,499	14,248
Development Costs 1) , 2)	28,428	13,330	41,758
Acquired unproved properties	0	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	11,889
Total	32,463	33,081	67,334

(1) Development costs include investments in Norway in facilities for liquefaction of natural gas and storage of LNG amounting to NOK 661 million in 2007 and NOK 112 million in 2006.

(2) Includes minor development costs in unproved properties.

Results of Operation for Oil and Gas Producing Activities

As required by Statement of Financial Accounting Standards No. 69 (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 to the financial statements but excluded from the table below relates to gas trading activities, transportation and business development as well as effects of disposals of oil and gas interests. Certain minor reclassifications have been made to prior periods' figures to be consistent with the current period's classifications.

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 2007			
Sales	(36)	(12,631)	(12,666)
Transfers	(172,077)	(27,705)	(199,782)
Total revenues	(172,113)	(40,336)	(212,448)
Exploration expense	3,638	7,695	11,333
Production costs	24,062	5,387	29,449
DD&A	23,030	11,103	34,133
Total costs	50,730	24,185	74,915
Results of operations before tax	(121,383)	(16,150)	(137,533)
Tax expense	97,184	7,070	104,254
Result of operations	(24,199)	(9,080)	(33,279)
Year ended December 2006			
Sales	(143)	(9,856)	(10,000)
Transfers	(175,476)	(20,523)	(195,999)
Total revenues	(175,619)	(30,379)	(205,999)
Exploration expense	3,480	7,170	10,650
Production costs	14,210	3,222	17,432
DD&A	20,938	14,370	35,308
Total costs	38,628	24,762	63,390
Results of operations before tax	(136,991)	(5,617)	(142,608)
Tax expense	106,131	4,006	110,137
Result of operations	(30,860)	(1,611)	(32,471)

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, and 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 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 judgement 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 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 a total of NOK 165,298 million of estimated future development costs as of 31 December 2007, an amount of NOK 95,974 million is expected to be spent within the next three years, as allocated in the table below.

Future development costs

(in NOK million)	2008	2009	2010	Total
Norway	25,495	21,875	17,154	64,524
Outside Norway	12,957	10,512	7,981	31,450
Total	38,452	32,387	25,135	95,974
Future development cost expected to be spent on proved undeveloped reserves	25,459	22,417	16,744	64,620

In 2007, StatoilHydro incurred NOK 41,758 million in development costs, of which NOK 19,758 million related to proved undeveloped reserves.

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

(in NOK million)	2007	2006
Standardised measure at beginning of year	245,714	278,511
Net change in sales and transfer prices and in production (lifting) costs related to future production	239,091	66,193
Changes in estimated future development costs	(30,740)	(46,659)
Sales and transfers of oil and gas produced during the period, net of production cost	(189,992)	(199,931)
Net change due to extensions, discoveries, and improved recovery	15,967	10,053
Net change due to purchases and sales of minerals in place	0	(950)
Net change due to revisions in quantity estimates	78,122	73,562
Previously estimated development costs incurred during the period	41,758	41,312
Accretion of discount	(54,374)	3,694
Net change in income taxes	(44,776)	19,929
Total change in the standardised measure during the year	55,056	(32,797)
Standardised measure at end of year	300,770	245,714

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 2007.

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 2007		Norway	Outside Norway	Total
Number of productive oil and gas wells				
Oil wells	— gross	816	819	1,635
	— net	288	144	432
Gas wells	— gross	152	130	282
	— net	66	48	115

At 31 December 2007 (in thousands of acres)		Norway	Outside Norway	Total
Developed and undeveloped oil and gas acreage				
Acreage developed	— gross	858	1,346	2,204
	— net	314	413	727
Acreage undeveloped	— gross	17,317	57,296	74,613
	— net	9,045	31,173	40,218

Remaining terms of leases and concessions are between one and 43 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 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	0.0	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, 2007.

At 31 December 2007		Norway	Outside Norway	Total
Number of wells in progress				
Developement Wells	— gross	46	82	128
	— net	17.6	13.7	31.3
Exploratory Wells	— gross	7	11	18
	— net	3.1	2,9	6.0

Average sales price and production cost per unit

	Norway	Outside Norway
Year ended 31 December 2007		
Average sales price crude in USD per bbl	70.9	69.1
Average sales price natural gas in NOK per Sm^3	1.69	1.17
Average production costs, in NOK per boe	46.3	34.4
Year ended 31 December 2006		
Average sales price crude in USD per bbl	63.6	60.9
Average sales price natural gas in NOK per Sm^3	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 2007 and 2006, and the related consolidated statements of income, recognised income and expense, and cash flows for each of the two years in the period ended 31 December 2007. 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 3 to the consolidated financial statements), which statements reflect total assets of NOK 124,954 million as of 31 December 2006, and total revenue and net income of NOK 97,910 million and NOK 11,093 million, respectively, for the year then ended. 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 and for the year ended 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 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the two years in the period ended 31 December 2007, 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), the effectiveness of StatoilHydro's internal control over financial reporting as of 31 December 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated 9 April 2008 expressed an unqualified opinion thereon.

Ernst & Young AS
Stavanger, Norway
9 April 2008

8.2.2 Report of Ernst & Young AS on StatoilHydro's internal control over financial reporting

To the Board of Directors
and Shareholders of StatoilHydro ASA

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

We have audited StatoilHydro ASA and subsidiaries' (StatoilHydro) internal control over financial reporting as of 31 December 2007, 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 under 7.11 Controls and procedures. 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, 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.

As indicated in the accompanying Management's report on internal control of financial reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Hydro Petroleum, which merged with Statoil ASA effective on 1 October 2007. Hydro Petroleum's financial statements are included in the 2007 consolidated financial statements of the StatoilHydro and constituted approximately 24% of total consolidated assets as of 31 December 2007 and 14% of consolidated total revenues for the year then ended. Additional revenues from Norsk Hydro oil and gas operations in 2007 representing 5% of total consolidated revenues have already been integrated in StatoilHydro sales processes. Our audit of internal control over financial reporting of the StatoilHydro also did not include an evaluation of the internal control over financial reporting of Hydro Petroleum.

In our opinion, StatoilHydro maintained, in all material respects, effective internal control over financial reporting as of 31 December 2007, 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 ("StatoilHydro") as of 31 December 2007 and 2006, and the related consolidated statements of income, recognised income and expense, and cash flows for each of the two years in the period ended 31 December 2007 and our report dated 9 April 2008, expressed an unqualified opinion thereon.

Ernst & Young AS

Stavanger, Norway
9 April 2008

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 balance sheet of Hydro Petroleum as of 31 December 2006, and the related combined statements of income, statements of comprehensive income, and cash flows 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 financial position of Hydro Petroleum as of 31 December 2006, and the results of its operations and its cash flows 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:

- ACQ means Annual Contract Quantity
- APA means Awards in Predefined Areas
- BTL means biomass-to-liquids process
- CCS means carbon capture and storage
- CHP means Combined heat and power plant
- E&P means Exploration & Production
- EFTA means European Free Trade Association
- EPN means Exploration & Production Norway business area
- FCC means Fluid Catalytic Cracking
- FPSO means Floating Production Storage Offloading
- GoM means Gulf of Mexico
- HSE means health, safety, security and the environment
- HTHP means High-temperature/high pressure
- IEA means International Energy Agency
- INT means International Exploration & Production business area
- IO means Integrated Operations
- IOR means Increased Oil Recovery
- M&M means Manufacturing and Marketing business area
- MPE means Norwegian Ministry of Petroleum and Energy
- NAOSC means North American Oil Sands Corporation
- NCS means Norwegian Continental Shelf
- NG means Natural Gas
- PRO means Projects
- PSA means production sharing agreement
- R&D means Research and Development
- ROACE means Return on Average Capital Employed
- SAGD means Steam Assisted Gravity Drainage
- SCP means South Caucasus Pipeline System
- SDFI means Norwegian State's Direct Financial Interest
- TNE means Technology & New energy functional area
- TSP means Technical Service Provider
- UKCS means UK Continental Shelf

Metric abbreviations etc:

- bbl means barrel
- mbbl means thousand barrels
- mmbbl means million barrels
- boe means barrels-of-oil equivalent
- mboe means thousand barrels-of-oil equivalent
- mmboe means million barrels-of-oil equivalent
- mmcf means million cubic feet
- bcf means billion cubic feet
- tcf means trillion cubic feet
- scm means standard cubic metre
- mcm means thousand cubic metres
- mmcm means million cubic metres
- bcm means billion cubic metres
- mmtpa means million tonnes per annum
- km means kilometre
- ppm means part per million
- one billion means 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 km 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
- 1,000 standard cubic metres of natural gas equals 6.29 boe
- 1 standard cubic foot equals 0.0283 standard cubic metres
- 1 standard cubic foot equals 1,000 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:

- 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.
- Condensates means 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
- LNG, or liquefied natural gas, means lean gas - primarily methane - converted to liquid form through refrigeration to minus 163 degrees Celsius under atmospheric pressures
- LPG means 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.
- Naphtha is an inflammable oil obtained by the dry distillation of petroleum
- Natural gas is petroleum that consists principally of light hydrocarbons. It can be divided into:
    - lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and
    - wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure
- NGL means natural gas liquids, light hydrocarbons mainly consisting of ethane, propane and butane which are liquid under pressure at normal temperature
- GTL, or gas to liquids, means the technology used for chemical conversion of natural gas into transportable liquids (diesel and naphtha) and specialty products (base oils)
- Petroleum is 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.

10 Cross reference to Form 20-F

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11 Forward looking statements

This Annual Report and Form 20-F contains forward-looking statements that involve risks and uncertainties, in particular under "Business overview" and "Operational review". In some cases, we use words such as "believe", "intend", "expect", "anticipate", "plan", "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; competitive position; expectations of the synergies produced by the merger with Norsk Hydro's oil and gas business; 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; projected operating costs; exploration expenditure; estimates of capital expenditure; expected exploration and development activities and plans; start-up dates for upstream and downstream activities; 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 forward-looking statements. Our actual results could differ materially from those anticipated in the forward-looking statements for many reasons, including the risks described above in "Risk review", and in "Operational review", and elsewhere in this Annual Report and 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; 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; the actions of competitors; the actions of field partners; natural disasters 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.

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