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

Net productive and dry oil and gas wells drilled
The following tables show the net productive and dry exploratory and development oil and gas wells completed or abandoned by Statoil in the past three years. Productive wells include wells in which hydrocarbons were discovered, and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing sufficient quantities to justify completion as an oil or gas well.

	Norway	Eurasia excluding Norway	Africa	Americas	Total
Year 2011					
Net productive and dry exploratory wells drilled	14.5	0.7	1.9	6.6	23.6
- Net dry exploratory wells drilled	4.8	0.4	0.8	2.7	8.7
- Net productive exploratory wells drilled	9.7	0.3	1.1	3.9	14.9
Net productive and dry development wells drilled	20.8	2.0	10.6	144.8	178.1
- Net dry development wells drilled	1.0	0.0	0.8	0.6	2.4
- Net productive development wells drilled	19.8	2.0	9.8	144.2	175.7
Year 2010					
Net productive and dry exploratory wells drilled	10.0	0.4	1.4	3.3	15.0
- Net dry exploratory wells drilled	3.1	0.4	0.7	1.9	6.0
- Net productive exploratory wells drilled	6.9	0.0	0.8	1.4	9.0
Net productive and dry development wells drilled	26.0	3.3	8.4	54.2	91.9
- Net dry development wells drilled	2.0	0.0	0.2	0.0	2.2
- Net productive development wells drilled	24.0	3.3	8.2	54.2	89.7
Year 2009					
Net productive and dry exploratory wells drilled	21.3	0.9	4.4	2.8	29.3
- Net dry exploratory wells drilled	9.6	0.3	2.1	1.0	13.0
- Net productive exploratory wells drilled	11.7	0.6	2.2	1.8	16.3
Net productive and dry development wells drilled	25.7	4.6	8.1	13.9	52.3
- Net dry development wells drilled	1.2	0.4	0.7	0.0	2.3
- Net productive development wells drilled	24.5	4.2	7.3	13.9	50.0

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

Exploratory and development drilling in process
The following table shows the number of exploratory and development oil and gas wells in the process of being drilled by Statoil at 31 December 2011

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

Top

3.9.4 Delivery commitments

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

On behalf of the Norwegian State's direct financial interest (SFDI), Statoil is responsible for managing, transporting and selling the Norwegian State's oil and gas from the Norwegian continental shelf (NCS). These reserves are sold in conjunction with our own reserves. As part of this arrangement, Statoil will deliver gas to customers under various types of sales contracts. In order to fulfil the commitments, we will utilise a field supply schedule that ensures the highest possible total value for Statoil and SDFI's joint portfolio of oil and gas.

The majority of our gas volumes in Norway are sold under long-term contracts with take-or-pay clauses. Statoil's and SDFI's annual delivery commitments under these agreements are expressed as the sum of the annual contract quantities (ACQ). As of 31 December 2011, the long-term commitments from NCS for the Statoil/SDFI arrangement amounted to a total of approximately 24 tcf (675 bcm).

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

Top

3.10 Applicable laws and regulations

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

The principal legislation governing our petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of 29 November 1996 (the "Petroleum Act") and the regulations issued thereunder, and the Norwegian Petroleum Taxation Act of 13 June 1975 (the "Petroleum Taxation Act"). The Petroleum Act sets out the principle that the Norwegian State is the owner of all subsea petroleum on the NCS, that exclusive right to resource management is vested in the Norwegian State and that the Norwegian State alone is authorised to award licences for petroleum activities. We are dependent on the Norwegian State for approval of our NCS exploration and development projects and our applications for production rates for individual fields.

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

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

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

Although Norway is not a member of the European Union (EU), it is a member of the European Free Trade Association (EFTA). The EU and the EFTA Member States have entered into the Agreement on the European Economic Area, referred to as the EEA Agreement, which provides for the inclusion of EU legislation covering the four freedoms - the free movement of goods, services, persons and capital - in the national law of the EFTA Member States (except Switzerland). An increasing volume of regulation affecting us is adopted in the EU and then applied to Norway under the EEA Agreement. As a Norwegian company operating both within EFTA and the EU, our business activities are subject to both the EFTA Convention governing intra-EFTA trade and EU laws and regulations adopted pursuant to the EEA Agreement.

Top

3.10.1 The Norwegian licensing system

Production licences are the most important type of licence awarded under the Petroleum Act, and the Norwegian Ministry of Petroleum and Energy has executive discretionary power to award and set the terms for production licences.

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

Production licences are the most important type of licence awarded under the Petroleum Act, and the Ministry of Petroleum and Energy has executive discretionary powers to award a production licence and to decide the terms of that licence. The Norwegian Government is not entitled to award us a licence in an area until the Storting has decided to open the area in question for exploration. The terms of our production licences are decided by the Ministry of Petroleum and Energy.

A production licence grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensees become the owners of the petroleum produced from the field covered by the licence. Notwithstanding the exclusive rights granted under a production licence, the Ministry of Petroleum and Energy has the power, in exceptional cases, to permit third parties to carry out exploration in the area covered by a production licence.

Production licences are normally awarded in licensing rounds. The first licensing round for NCS production licences was announced in 1965. The award of the first licences covered areas in the North Sea. Over the years, the awarding of licences has moved northward to cover areas in both the Norwegian Sea and the Barents Sea. In recent years, the principal licensing rounds have largely concerned licences in the Norwegian Sea. However, in the future, we expect an increase in licencing rounds concerning licences in the Barents sea.

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

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

The governing body of the joint venture is the management committee. In licences awarded since 1996 where the State's Direct Financial Interest (SDFI) holds an interest, the Norwegian State, acting through Petoro AS, may veto decisions made by the joint venture management committee, which, in the opinion of the Norwegian State, would not be in compliance with the obligations of the licence with respect to the Norwegian State's exploitation policies or financial interests. This veto power has never been used.

The day-to-day management of a field is the responsibility of an operator appointed by the Ministry of Petroleum and Energy. The operator is in practice always a member of the joint venture holding the production licence, although this is not legally required. The terms of engagement of the operator are set out in the joint operating agreement, under which the operator can normally terminate its engagement by giving six months' notice. However, with the consent of the Ministry of Petroleum and Energy, the management committee may instruct the operator to continue to perform its duties until a new operator has been appointed. The management committee can terminate the operator's engagement by giving six months' notice through an affirmative vote by all members of the management committee other than the operator. A change of operator requires the consent of the Ministry of Petroleum and Energy. In special cases, the Ministry of Petroleum and Energy can order a change of operator.

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

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

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

If important public interests are at stake, the Norwegian State may instruct us and other licensees on the NCS to reduce the production of petroleum. The last time the Norwegian State instructed a reduction in oil production was in 2002.

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

A licence from the Ministry of Petroleum and Energy is also required in order to establish facilities for the transportation and utilisation of petroleum. When applying for such licences, the owners, who in practice are licensees under a production licence, must prepare a plan for installation and operation. Licences for the establishment of facilities for the transportation and utilisation of petroleum will normally be awarded subject to certain conditions. Typically, these conditions require the facility owners to enter into a participants' agreement. Ownership of most facilities for the transportation and utilisation of petroleum in Norway and on the NCS is organised in the form of joint ventures of a group of licence holders. The participants' agreements are similar to the joint operating agreements.

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

The Norwegian State is entitled to take over the fixed facilities of the licensees when a production licence expires, is relinquished or revoked. In respect of facilities on the NCS, the Norwegian State decides whether any compensation will be payable for facilities thus taken over. If the Norwegian State should choose to take over onshore facilities, the ordinary rules of compensation in connection with the expropriation of private property apply.

Licences for the establishment of facilities for the transportation and utilisation of petroleum typically include a clause whereby the Norwegian State can require that the facilities be transferred to it free of charge on expiry of the licence period.

Top

3.10.2 Gas sales and transportation

We market gas from the NCS on our own behalf and on the Norwegian State's behalf. Gas is transported through the Gassled pipeline network to customers in the UK and mainland Europe.

Most of our and the Norwegian State's gas produced on the NCS is sold under long-term gas contracts to customers in the European Union (EU). The EU internal energy market has been high on the European Commission's agenda, and this market has thus been subject to continuous legislative initiatives. Such changes in EU legislation may affect Statoil's marketing of gas. In 2009, the European Commission issued a third legislative package for an internal EU gas and electricity market. It has yet to be fully implemented in the EU Member States' national laws, however.

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

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

The tariffs for use of capacity in the transport system are determined by applying a formula set out in separate tariff regulations stipulated by the Ministry of Petroleum and Energy. The Ministry's main objective when setting the tariffs is to ensure that the profits are extracted in the production fields on the NCS and not in the transport system. The tariffs are paid on the basis of booked capacity, not on the basis of the volumes actually transported.

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

Top

3.10.3 HSE regulation

Our petroleum operations are subject to extensive laws and regulations relating to health, safety and the environment (HSE).

Norway

Under the Petroleum Act of 29 November 1996, our oil and gas operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in step with technological developments.

Following the incident that occurred on the BP-operated Macondo well in the deepwater Gulf of Mexico, USA, in April 2010, the Norwegian Ministry of Petroleum and Energy announced that the incident could result in changes to laws and regulations concerning activities on the NCS. After a review of the regulations, no changes were imposed.

However, on 27 October 2011, the European Commission proposed a new offshore safety regulation with the objective of reducing the risk of a major incident in European Union (EU) waters and limiting the consequences should such an incident occur. The draft regulation is now subject to a consultation procedure among the EU Member States, which is not expected to conclude until late 2012. If enforced in the EU and subsequently adopted in the European Economic Area (EEA) of which Norway is part, the regulation would apply to our activities on the NCS. The effects, if any, of it are not possible to foresee until the legislative process is finalised.

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

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

We are required at all times to have a plan to deal with emergency situations in our petroleum operations. During an emergency, the Norwegian Ministry of Labour/ Norwegian Ministry of Fisheries and Coastal Affairs/Norwegian Coastal Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the licensees' account.

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

International
With business operations in 41 countries and territories, Statoil is subject to a wide variety of HSE laws and regulations concerning its products, operations and activities. As a result of the Macondo incident, in 2011, the US Department of the Interior created two new agencies to administer operations and activities in the Gulf of Mexico - the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Offshore Energy Management (BOEM). The Department also issued new regulations to address the respective roles of the new agencies. Application of these regulations has the potential to affect our operations.

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

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

Top

3.10.4 Taxation of Statoil

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

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

Corporate income tax
Our profits, both from offshore oil and natural gas activities and from onshore activities, are subject to Norwegian corporate income tax. The corporate income tax rate is currently 28%. Our profits are computed in accordance with ordinary Norwegian corporate income tax rules, subject to certain modifications that apply to companies engaged in petroleum operations. Gross revenue from oil production and the value of lifted stocks of oil are determined on the basis of norm prices. Norm prices are decided on a daily basis by the Petroleum Price Board, a body whose members are appointed by the Norwegian Ministry of Petroleum and Energy. Norm prices are published quarterly. The Petroleum Taxation Act states that the norm prices shall correspond to the prices that could have been obtained in a sale of petroleum between independent parties in a free market. When stipulating norm prices, the Petroleum Price Board takes a number of factors into consideration, including spot market prices and contract prices in the industry.

The maximum rate of depreciation of development costs related to offshore production installations and pipelines is 16.67% per year. Depreciation starts when the cost is incurred. Exploration costs may be deducted in the year in which they are incurred. Financial costs related to the offshore activity are calculated directly based on a formula set out in the Petroleum Tax Act. The financial costs deductible under the offshore tax regime are the total financial costs multiplied by 50% of tax values divided by the average interest-bearing debt. All other financial costs and income are allocated to the onshore tax regime.

Any tax losses can be carried forward indefinitely against subsequent income earned. Fifty per cent of losses relating to activity conducted onshore in Norway can be deducted from NCS income subject to the 28% tax rate. Losses on foreign activities cannot be deducted from NCS income. Losses on offshore activities are fully deductible from onshore income.

By using group contributions between Norwegian companies in which we hold more than 90% of the shares and votes, tax losses and taxable income can be offset to a great extent. Group distributions are not deductible from our offshore income.

Dividends received are subject to tax in Norway. The basis for taxation is 3% of the dividend received, which is subject to the standard 28% income tax rate. Dividends from low-tax countries or portfolio investments outside the EEA will, under certain circumstances, be subject to the standard 28% income tax rate based on the full amounts received.

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

Special petroleum tax
A special petroleum tax is levied on profits from petroleum production and pipeline transportation on the NCS. The special petroleum tax is currently levied at a rate of 50%. The special tax is applied to relevant income in addition to standard 28% income tax, resulting in a 78% marginal tax rate on income subject to petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible from the special petroleum tax, and a tax-free allowance, or uplift, is granted at a rate of 7.5% per year. The uplift is computed on the basis of the original capitalised cost of offshore production installations. The uplift can be deducted from taxable income for a period of four years, starting in the year in which the capital expenditure is incurred. Unused uplift can be carried forward indefinitely.

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

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

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

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

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

Taxation outside Norway
Statoil's international petroleum activities are subject to tax pursuant to local legislation. Fiscal regulation of our upstream operations is generally based on corporate income tax regimes and/or production sharing agreements (PSA). Royalties may apply in either case.

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

Production sharing agreements (PSA)
Under a PSA, the host government typically retains the right to the hydrocarbons in place. The contractor normally receives a share of the oil produced to recover its costs, and is also entitled to an agreed share of the oil as profit. The state's share of profit oil is typically increases based on a success factor, such as surpassing certain specified internal rates of return, production rates or accumulated production. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery and are then entitled to recover those costs during the producing phase. Fiscal provisions in a PSA are to a large extent negotiable and are unique to each PSA. Parties to a PSA are generally insulated, via the terms of the PSA, against legislative changes in a country's general tax laws.

Income tax regimes
Under an income tax/royalty regime, companies are granted licences by the government to extract petroleum, and the state may be entitled to royalties in addition to tax based on the company's net taxable income from production. In general, the fiscal terms surrounding these licences are not negotiable and the company is subject to legislative changes in the tax laws.

Top

3.10.5 The Norwegian State's participation

The Norwegian State's policy as a shareholder in Statoil has been and continues to be to ensure that petroleum activities create the highest possible value for the Norwegian State.

Initially, the Norwegian State's participation in petroleum operations was largely organised through Statoil. In 1985, the Norwegian State established the State's Direct Financial Interest (SDFI) through which the Norwegian State has direct participating interests in licences and petroleum facilities on the NCS. As a result, the Norwegian State holds interests in a number of licences and petroleum facilities in which we also hold interests. Petoro AS, a company wholly owned by the Norwegian State, was formed in 2001 to manage the SDFI assets.

Top

3.10.6 SDFI oil & gas marketing & sale

We market and sell the Norwegian State's oil and gas as part of our own production. The Norwegian State has chosen to implement this arrangement.

Accordingly, at an extraordinary general meeting held on 27 February 2001, the Norwegian State, as sole shareholder, revised our articles of association by adding a new article that requires us to continue to market and sell the Norwegian State's oil and gas together with our own oil and gas in accordance with an instruction established in shareholder resolutions in effect from time to time. At an extraordinary general meeting held on 25 May 2001, the Norwegian State, as sole shareholder, approved a resolution containing the instruction referred to in the new article. This resolution is referred to as the owner's instruction.

The Norwegian State has a coordinated ownership strategy aimed at maximising the aggregate value of its ownership interests in Statoil and the Norwegian State's oil and gas. This is reflected in the owner's instruction to Statoil. It contains a general requirement that, in our activities on the NCS, we must take account of these ownership interests in decisions that could affect the execution of this marketing arrangement.

The owner's instruction sets out specific terms for the marketing and sale of the Norwegian State's oil and gas. The principal provisions of the owner's instruction are set out below.

Objectives
The overall objective of the marketing arrangement is to obtain the highest possible total value for our oil and gas and the Norwegian State's oil and gas, and to ensure an equitable distribution of the total value creation between the Norwegian State and Statoil. In addition, the following considerations are important:

- to create the basis for long-term and predictable decisions concerning the marketing and sale of the Norwegian State's oil and gas;
- to ensure that results, including costs and revenues related to our oil and gas and the Norwegian State's oil and gas, are transparent and measurable; and
- to ensure efficient and simple administration and execution.

Our tasks
Our main tasks under the owner's instruction are to market and sell the Norwegian State's oil and gas and to carry out all the necessary related activities, other than those carried out jointly with other licensees under the production licence. This includes, but is not limited to, responsibility for processing, transport and marketing. In the event that the owner's instruction is terminated in whole or in part by the Norwegian State, the owner's instruction provides for a mechanism under which contracts for the marketing and sale of the Norwegian State's oil and gas to which we are party may be assigned to the Norwegian State or its nominee. Alternatively, the Norwegian State may require that the contracts be continued in our name, but that, in the underlying relationship between the Norwegian State and us, the Norwegian State has all rights and obligations relating to the Norwegian State's oil and gas.

Costs
The Norwegian State does not pay us a specific consideration for performing these tasks, but reimburses us for its proportionate share of certain costs, which, under the owner's instruction, may be our actual costs or an amount specifically agreed.

Price mechanisms
Payment to the Norwegian State for sales of the Norwegian State's natural gas, both to us and to third parties, is based either on the prices achieved, a net back formula or market value. We now purchase all of the Norwegian State's oil and NGL. Pricing of the crude oil is based on market-reflective prices. NGL prices are based on either achieved prices, market value or market-reflective prices.

Lifting mechanism
To ensure neutral weighting between the Norwegian State's and our own natural gas volumes, a list has been established for deciding the priority between each individual field. The different fields are ranked in accordance with their assumed total value creation for the Norwegian State and Statoil, assuming that all of the fields meet our profitability requirements if we participate as a licensee, and the Norwegian State's profitability requirements if the State is a licensee. Within each individual field in which both the Norwegian State and Statoil are licensees, the Norwegian State and Statoil will deliver volumes and share income in proportion to our respective participating interests.

The Norwegian State's oil and NGL is lifted together with our oil and NGL in accordance with applicable lifting procedures for each individual field and terminal.

Withdrawal or amendment
The Norwegian State may at any time utilise its position as majority shareholder of Statoil to withdraw or amend the owner's instruction.

Top

3.11 Competition

There is intense competition in the oil and gas industry for customers, production licences, operatorships, capital and experienced human resources.

Statoil competes with large integrated oil and gas companies, as well as with independent and state-owned companies, for the acquisition of assets and licences for the exploration, development and production of oil and gas, and for the refining, marketing and trading of crude oil, natural gas and related products. Oil and gas prices and demand, exploration and production costs, global production levels, alternative fuels, and government - including environmental - regulations are key factors affecting competition in the oil and gas industry.

Statoil's ability to remain competitive will depend, among other things, on its management continuing to focus on reducing unit costs and improving efficiency, maintaining long-term growth in our reserves and production through continuing technological innovation. It will also depend on our ability to seize international opportunities in areas where our competitors may also be actively pursuing exploration and development opportunities. We believe that we are in a position to compete effectively in each of our business segments.

Top

3.12 Property, plants and equipment

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

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

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

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

Top

3.13 Related party transactions

We have the following transactions with related parties.

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

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

Because the Norwegian State controls a substantial proportion of the industry in Norway, there are many state-controlled entities with which we do business. The financial value of most such transactions is relatively small, and the ownership interest of the Norwegian State in such counterparties has not had any effect on the arm's-length nature of the transactions. A full overview of the Norwegian State's shareholdings in commercial entities can be found here: www.regjeringen.no/nb/dep/nhd/tema/eierskap/statlig-eierskap/forvaltning-av-statlige-eierandeler.html?id=383095

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

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

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

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

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

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

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

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

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

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

Top

3.14 Insurance

Among other things, Statoil takes out insurance policies for physical loss of or damage to our oil and gas properties, liability to third parties, workers' compensation and employer's liability, general liability, pollution and well control.

Our insurance policies are subject to:

- Deductibles, excesses and self-insured retentions (SIR) that must be borne prior to recovery
- Exclusions and limitations.

Our well control policy, which covers costs relating to well control incidents (including pollution and clean-up costs), is subject to a gross limit per incident. The gross limits for our two most significant geographical areas, the NCS and the Gulf of Mexico (GoM), USA, are:

NCS

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

GoM

- USD 1,300 million (approximately NOK 7,800 million) per incident for exploration wells
- USD 300 million (approximately NOK 1,800 million) per incident for production wells.

The limits assume a 100% ownership interest in a given well and would be scaled to be equivalent to our percentage ownership interest in a given well. Our SIR for well control policies varies between NOK 7.6 million and NOK 100 million per loss on the NCS depending on our percentage ownership interest in the well and certain other factors. Our SIR in the GoM would be approximately USD 10 million (approximately NOK 60 million) per incident assuming 100% ownership. In addition to the well control insurance programmes, we have in place a third-party liability insurance programme with a gross limit of USD 800 million (approximately NOK 4,800 million) per incident. The SIR is insignificant (maximum NOK 6 million).

We have a variety of other insurance policies related to other projects worldwide for which we have limited SIR.

There is no guarantee that our insurances will adequately protect us against liability for all potential consequences or damages.

Top

3.15 People and the group

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

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

Through global people policies, Statoil aims to ensure consistent common standards across the organisation. Together with our values and ethics code of conduct, our people policies are the most important guidelines for the people processes. We endeavour to ensure a good match between the professional interests and goals of every employee and the needs of the business. Through our global development and deployment process, we endeavour to offer challenging and meaningful job opportunities. Statoil remains committed to providing financial and non-financial rewards that attract and motivate the right people, and it continues to focus on equal opportunities for all employees.

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

Top

3.15.1 Employees in Statoil

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

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

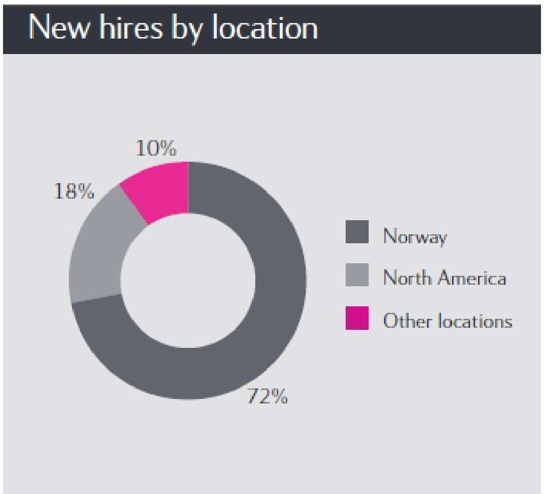
	Number of employees			Women		
Geographical Region	**2011**	2010	2009	2011	2010	2009
Norway	**20,021**	18,838	18,100	31 %	31 %	31 %
Rest of Europe	**10,187**	10,335	9,593	50 %	49 %	50 %
Africa	**121**	140	165	28 %	30 %	28 %
Asia	**146**	145	150	59 %	58 %	55 %
North America	**1,030**	713	584	34 %	33 %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

*Statoil Fuel and Retail employees are included

Geographical Region	**Permanent employees 2011**	Consultants	Total Workforce*	% Consultants**	% Part - Time	New Hires
Norway	**20,021**	4758	24,779	19 %	3 %	1,697
Rest of Europe	**10,187**	2460	12,647	19 %	1 %	1,849
Africa	**121**	43	164	26 %	NA	6
Asia	**146**	22	168	13 %	NA	30
North America	**1,030**	138	1,168	12 %	NA	352
South America	**210**	299	509	59 %	NA	51
TOTAL	**31,715**	7,720	39,435	20 %	3 %	3,985
Non - OECD	**2,773**	437	3,210	14 %	NA	594

*Total workforce consists of number of permanent employees and consultants
** Consultants do not include enterprise personnel

Statoil works systematically with recruitment and development programmes in order to build a diverse workforce by attracting, recruiting and retaining people of both genders and different nationalities and age groups across all types of positions. In 2011, Statoil recruited 1,900 new employees worldwide. While 70% were recruited to jobs in Norway, 18% were recruited to our business in North America, reflecting our growth ambitions in that region. In 2011, 43% of our new hires were women and 65% other nationalities than Norwegian.



We believe Statoil's low turnover rates reflect a high level of satisfaction and engagement among its employees, which is also supported by the results of the annual organisational and working environment survey. In Statoil ASA, the total turnover rate for 2011 was 1.4%. The figure opposite provides an overview of the total turnover rate by gender and age in Statoil ASA from 2009 to 2011 (number excluding the reporting segment SFR).

Top

3.15.2 Equal opportunities

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

At 31 December 2011, the overall percentage of women in the company was 37%, and 40% of the board of directors were women, and 20% of the corporate executive team were women. The focus on diversity issues is also reflected in the company's people strategy. We aim to increase the number of female managers, and we endeavour to give equal representation to men and women in leadership development programmes. At the end of December 2011, the total proportion of female managers in Statoil was 31%, and, among managers under the age of 45, the proportion was 32% (number excluding the reporting segment SFR).

We also devote close attention to male-dominated positions and discipline areas. In 2011, 26% of staff engineers were women, and among staff engineers with up to 20 years' experience, the proportion of women was 30 %.

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

Cultural diversity
We believe that being a global and sustainable company requires people with a global mindset. One way to build a global company is to ensure that recruitment processes both within and outside Norway contribute to a culturally diverse workforce. Outside Norway, we need to continue to focus on increasing the number of people and managers that are locally recruited, and to reduce long-term, extensive use of expats in our business operations. At year end 2011, 41% of the managerial staff in the Statoil group held nationalities other than Norwegian.

Top

3.15.3 Unions and representatives

Statoil's cooperation with employee representatives and trade unions is based on confidence, trust and continuous dialogue between management and the people in various cooperative bodies.

In Statoil, 68% of the employees in the parent company are members of a trade union. Work councils and working environment committees are established where required by law or agreement. Town hall meetings are also used for information and consultations in accordance with requirements and usage in each country.

In Norway, the formal basis for collaboration with labour unions is established in the Basic Agreements between the Confederation of Norwegian Enterprise (NHO) and the five Statoil unions.

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

Top

4 Financial analysis and review

Statoil delivered strong financial results and cash flows in 2011. Production was lower than 2010 but in line with

expectations and important strategic progress was made. Discoveries were made in 22 out of 41 exploration wells.

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

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

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

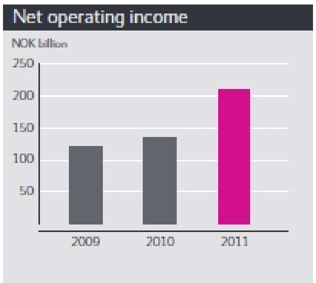
The board of directors is proposing a dividend of NOK 6.50 per share for 2011.

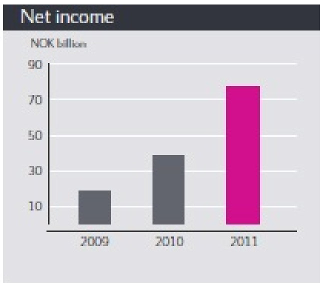
As stated in note 2 *Significant accounting policies*, Statoil changed its policy for accounting for jointly controlled entities under IAS 31 Interests in Joint Ventures, from the application of the equity method to the proportionate consolidation method with effect from 2011. Proportionate consolidation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

Top

4.1 Operating and financial review 2011

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





In 2011, Statoil delivered total entitlement liquids and gas production of 1,650 mboe per day, down 3% from 1,705 mboe per day in 2010. Total equity liquids and gas production decreased by 2% from 2010, to 1,850 mboe per day in 2011, mainly caused by reduced water injection at Gullfaks, challenges primarily related to risers, maintenance shut downs and deferral of gas sales. In addition, expected reductions due to natural decline on mature fields and suspended production in Libya contributed to the decrease. This decrease was partly offset by production from start-up of new fields, ramp-up of production on existing fields and increased ownership shares.

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

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

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

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

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

Top

4.1.1 Sales volumes

Sales volumes include our lifted entitlement volumes, the sale of SDFI volumes and our marketing of third-party volumes.

We take part in the production of oil and natural gas volumes, and incur capital expenditures and operating expenses on the basis of such equity volumes. Under certain production-sharing agreements (PSAs), a portion of the equity production is distributed to the relevant government before arriving at the volumes that we are ultimately entitled to sell (entitlement volumes). The timing of our lifting of our share of entitlement volumes may cause there to be a difference at any given time between our share of entitlement volumes and the volumes lifted. This difference is called overlift if we have lifted more than our share of the entitlement production, and underlift if our cumulative lifting is less than our share of the entitlement volumes. The lifted volumes and volumes in inventory are the basis for what we can sell to third parties. Revenues are based on lifted volumes.

In addition to our own volumes of lifted entitlement production and production in storage, we market and sell oil and gas owned by the Norwegian state through the Norwegian state's share in production licences. This is known as the State's Direct Financial Interest, or SDFI. For additional information, see the section *Operational review - Applicable laws and regulations- SDFI oil & gas marketing & sale*. The following table shows SDFI and Statoil sales volume information for crude oil and natural gas, as applicable, for the periods indicated. The Statoil natural gas sales volumes include equity volumes sold by the segment MPR, natural gas volumes sold by the segment DPI and ethane volumes.

For more information on the differences between equity and entitlement production, sales volumes and lifted volumes, see the section Financial analysis and review - *Operating and financial review 2011 - Definitions of reported volumes.*

Sales Volumes	Year ended 31 December 2011	2010	2009
Statoil:[1]			
Crude oil (mmbbls)[2]	**332**	354	381
Natural gas (bcf)	**1,377**	1,472	1,462
Natural gas (bcm)[3]	**39.0**	41.7	41.4
Combined oil and gas (mmboe)	**577**	616	642
Third party volumes:[4]			
Crude oil (mmbbls)[2]	**333**	310	257
Natural gas (bcf)	**244**	247	192
Natural gas (bcm) [3]	**6.9**	7.0	5.4
Combined oil and gas (mmboe)	**376**	354	291
SDFI assets owned by the Norwegian State:			
Crude oil (mmbbls)[2]	**162**	172	200
Natural gas (bcf)	**1,476**	1,610	1,431
Natural gas (bcm)[3]	**41.8**	45.6	40.5
Combined oil and gas (mmboe)	**425**	458	455
Total			
Crude oil (mmbbls)[2]	**827**	835	838
Natural gas (bcf)	**3,096**	3,329	3,085
Natural gas (bcm)[3]	**87.7**	94.3	87.4
Combined oil and gas (mmboe)	**1,378**	1,428	1,388

[1] The Statoil volumes included in the table above are based on the premise that volumes sold were equal to lifted volumes in the relevant year. Changes in inventory may cause these volumes to differ from the sales volumes reported elsewhere in this report by MPR in that such volumes include volumes still in inventory or transit held by other reporting entities within the group. Excluded from such volumes are volumes lifted by DPI but not sold by the MPR, and volumes lifted by DPN or DPI and still in inventory or in transit.
[2] Sales volumes of crude oil include NGL and condensate. All sales volumes reported in the table above include internal deliveries to our manufacturing facilities.
[3] At a gross calorific value (GCV) of 40 MJ/scm.
[4] Third party volumes of crude oil include both volumes purchased from partners in our upstream operations and other cargos purchased in the market. The third party volumes are purchased either for sale to third parties or for our own use. Third party volumes of natural gas include third party LNG volumes related to our activities at the Cove Point regasification terminal in the U.S.

Top

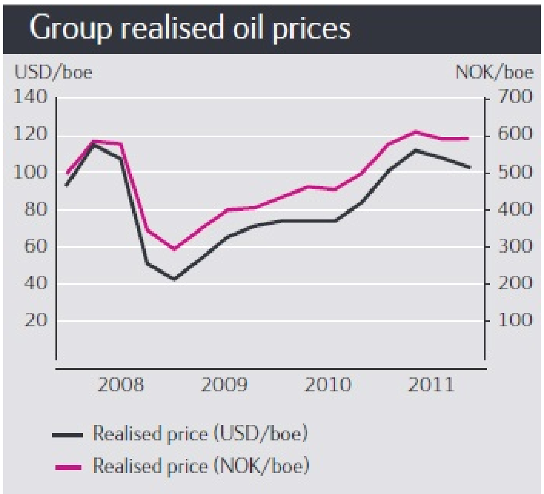
4.1.2 Group profit and loss analysis

Net operating income was NOK 211.8 billion in 2011, a 54% increase compared to 2010 mainly due to higher prices, reduced net impairment losses, unrealised gains on derivatives and gains on sale of assets.

IFRS Income statement (in NOK billion)	For the year ended 31 December 2011	2010 (restated)	2009 (restated)	11-10 change	10-09 change
Revenues and other income					
Revenues	**645.6**	527.0	462.5	23%	14%
Net income from associated companies	**1.3**	1.2	1.5	8%	(20%)
Other income	**23.3**	1.8	1.4	>100%	31%
Total revenues and other income	**670.2**	529.9	465.4	26%	14%
Operating expenses					
Purchase [net of inventory variation]	**319.6**	257.4	205.9	24%	25%
Operating expenses and Selling, general and administrative expenses	**73.6**	68.8	67.3	7%	2%
Depreciation, amortisation and net impairment losses	**51.4**	50.7	53.8	1%	(6%)
Exploration expenses	**13.8**	15.8	16.7	(12%)	(5%)
Total operating expenses	**(458.4)**	(392.7)	(343.7)	17%	14%
Net operating income	**211.8**	137.3	121.7	54%	13%
Net financial items	**2.1**	(0.4)	(6.8)	>100 %	(94%)
Income before tax	**213.8**	136.8	114.9	56%	19%
Income tax	**(135.4)**	(99.2)	(97.2)	37%	2%
Net income	**78.4**	37.6	17.7	>100%	>100%
Earnings per share for income attributable to equity holders of the company diluted	**24.7**	11.9	5.7	>100%	>100%

Operational data	For the year ended 2011	2010	2009	11-10 Change	10-09 Change
Average liquids price (USD/bbl)	**105.6**	76.5	58.0	38 %	32 %
USDNOK average daily exchange rate	**5.61**	6.05	6.30	(7 %)	(4 %)
Average liquids price (NOK/bbl)	**592**	462	364	28 %	27 %
Average gas prices (NOK/scm)	**2.08**	1.72	1.90	21 %	(10 %)
Refining reference margin (USD/bbl)	**2.3**	3.9	3.0	(41 %)	30 %
Total entitlement liquids production (mboe per day)	**945**	968	1,066	(2 %)	(9 %)

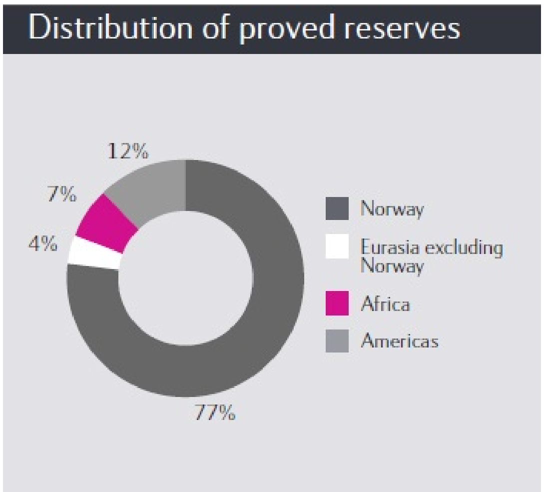
Total entitlement gas production (mboe per day)	**706**	738	740	(4 %)	(0 %)
Total entitlement liquids and gas production (mboe per day)	**1,650**	1,705	1,806	(3 %)	(6 %)
Total equity liquids production (mboe per day)	**1,118**	1,122	1,202	(0 %)	(7 %)
Total equity gas production (mboe per day)	**732**	766	760	(4 %)	1 %
Total equity liquids and gas production (mboe per day)	**1,850**	1,888	1,962	(2 %)	(4 %)
Total liquids liftings (mboe per day)	**910**	969	1,045	(6 %)	(7 %)
Total gas liftings (mboe per day)	**706**	738	740	(4 %)	(0 %)
Total liquids and gas liftings (mboe per day)	**1,616**	1,706	1,785	(5 %)	(4 %)
Production cost entitlement volumes (NOK/boe, last 12 months)	**48.4**	42.8	38.4	13 %	11 %
Production cost equity volumes (NOK/boe, last 12 months)	**43.1**	38.6	35.3	12 %	9 %
Equity production cost excluding restructuring and gas injection cost (NOK/boe, last 12 months)	**42.4**	37.9	35.3	12 %	7 %



Total revenues and other income amounted to NOK 670.2 billion in 2011 compared to NOK 529.9 billion in 2010 and NOK 465.4 billion in 2009. Most of the revenues stem from the sale of lifted crude oil, natural gas and refined products produced and marketed by Statoil. In addition, we also market and sell the Norwegian State's share of liquids from the NCS. All purchases and sales of the Norwegian State's production of liquids are recorded as purchases net of inventory variations and sales, respectively, while sales of the Norwegian State's share of gas from the NCS are recorded net.

The NOK 118.6 billion increase in **revenues** from 2010 to 2011 was mainly attributable to higher prices for both liquids and gas, partly offset by lower volumes of both liquids and gas sold. The variance on unrealised net gains on derivatives contributed NOK 12.0 billion to the increase in revenues between the years. Average prices of liquids measured in NOK increased by 28% from 2010 to 2011, contributing NOK 43.2 billion to the increase in revenues, while average gas prices measured in NOK increased by 21%, contributing NOK 18.3 billion. The increase was partly offset by a 6% decrease in liftings of liquids and a 4% decrease in total liftings of gas, with off-setting effects of NOK 9.9 billion and NOK 4.1 billion, respectively.

The NOK 64.5 billion increase in revenues from 2009 to 2010 was mainly attributable to higher prices for liquids and increased volumes of gas sold, partly offset by lower gas prices, reduced volumes of liquids sold and losses on derivatives. Realised prices of liquids measured in NOK increased by 27% from 2009 to 2010, contributing NOK 34.6 billion to the increase in revenues, while increased volumes of gas sold contributed NOK 5.9 billion to the increase in revenues. The increase was partly offset by a 7% decrease in liftings of liquids with a negative contribution of NOK 10.1 billion, while gas prices were down by 10% in 2010, affecting revenues negatively by NOK 9.5 billion.

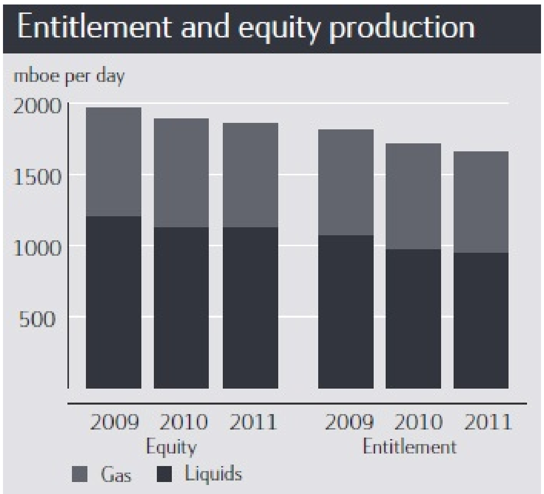


Over time, the volumes lifted and sold will equal our production of entitlement volumes, but they may be higher or lower in any period due to differences between the capacity of the vessels lifting our volumes and the actual entitlement production in the period.

Total liquids **liftings** were 910 mboe per day in 2011, a decrease of 6% compared to 2010. Total liquids liftings were 969 mboe per day in 2010, a decrease of 7% compared to 2009 when total liquids liftings were 1,045 mboe per day. The average underlift was 34 mboe per day in 2011. In 2010, the average overlift was 1 mboe per day and in 2009, the average underlift was 21 mboe per day.

Entitlement volumes lifted form the basis for revenue recognition, while equity production volumes affect operating costs more directly. See the report section Financial analysis and review - Operating and financial review 2011 - Sales volumes, for more details on the production-sharing agreement (PSA) effects that cause differences between equity and entitlement volumes. See below for more details on the difference between lifted and produced volumes.

Total entitlement liquids and gas production decreased from 1.705 mmboe per day in 2010 to 1.650 mmboe per day in 2011. In 2009, total entitlement liquids and gas production was 1.806 mmboe per day.



Total equity liquids and gas production decreased from 1.888 mmboe per day in 2010 to 1.850 mmboe per day in 2011. In 2009, total equity production of liquids and gas was 1.962 mmboe per day.

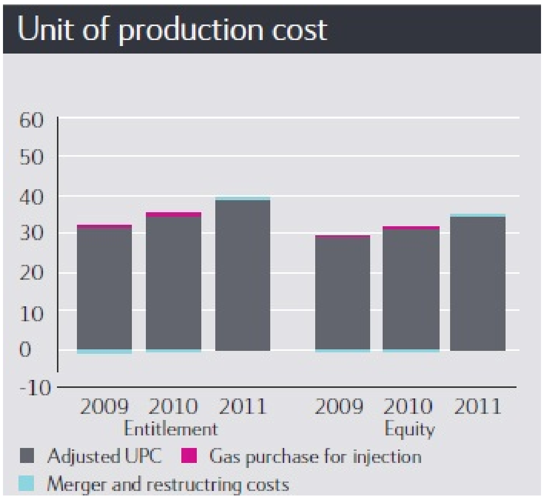
The 2% decrease in total equity production in 2011 compared to 2010 was primarily caused by reduced water injection at Gullfaks, riser inspections and repairs, maintenance shut downs and deferral of gas sales. In addition, expected reductions due to natural decline on mature fields and suspended production in Libya contributed to the decrease. This decrease was partly offset by production from start-up of new fields, ramp-up of production on existing fields and increased ownership shares. Total entitlement production decreased by 6% from 2010 to 2011 and was impacted by the reduction in equity production and by increasing PSA effects.

The 4% decrease in total equity production in 2010 compared to 2009, was primarily caused by relatively higher maintenance activity in 2010 leading to production shutdowns, limitations in the gas transportation system from the NCS because of planned maintenance, production permit restrictions on the Ormen Lange field, various operational issues and a natural production decline on several mature fields. The decrease in equity production was partly compensated by production from the start-up of new fields and ramp-up on existing fields. Total entitlement production decreased by 6% from 2009 to 2010. It was impacted by the same factors as equity production and also by changes in profit tranches for some of our fields in Angola and higher prices leading to reduced entitlement shares on other fields.

The production cost per boe of entitlement volumes was NOK 48.4 for the 12 months ending 31 December 2011, compared with NOK 42.8 for the 12 months ending 31 December 2010. In 2009, the production cost per boe was NOK 38.4. Equity volumes represent produced volumes under PSA contracts that correspond to Statoil's ownership percentage in a specific field, while entitlement volumes represent Statoil's share of the volumes distributed to the partners in the field, which are subject to deductions. Production costs are incurred on the basis of our equity production. The management therefore believes that unit of production cost based on equity production is a better measure of cost control than unit of production cost based on entitlement volumes.

Based on equity volumes, the production cost per boe for the 12 months ending 31 December 2011 and 2010 was NOK 43.1 and NOK 38.6, respectively. In 2009, the production cost per boe was NOK 35.3. Adjusted for restructuring costs, reversal of restructuring costs and other costs arising from the merger recorded in the fourth quarter 2007 and gas injection costs, the production cost per boe of equity production for the 12 months ending 31 December 2011 and 2010, was NOK 42.4 and NOK 37.9, respectively. The corresponding figure for 2009 was NOK 35.3.

Adjustments are made for certain costs relating to the purchase of gas used for injection into oil-producing reservoirs. The adjustment facilitates comparison of field production costs with other fields that do not pay for their own gas used for injection into oil-producing reservoirs.



The increase in **adjusted production cost per boe** from 2010 to 2011, is mainly related to higher costs from fields preparing for production start-up and entering the production ramp-up phase resulting in a relatively higher cost per boe from new fields coming on stream.

Net income from associated companies was NOK 1.3 billion in 2011, NOK 1.2 billion in 2010 and NOK 1.5 billion in 2009.

Other income was NOK 23.3 billion in 2011, compared to NOK 1.8 billion in 2010 and NOK 1.4 billion in 2009. The significant increase in other income from 2010 to 2011 stems mainly from gains on sale of assets primarily related to the reduction of interests in Peregrino, the Kai Kos Dehseh oil sands and Gassled on 2011. The increase in other income from 2009 to 2010 was mainly related to a gain on sale of assets and insurance proceeds relating to business interruptions.

Purchase [net of inventory variation] includes the cost of the liquids production purchased from the Norwegian State pursuant to the Owners Instruction. See section *Operational review - Applicable laws and regulations- SDFI oil & gas marketing & sale* for more details. The purchase, net of inventory variation amounted to NOK 319.6 billion in 2011, compared to NOK 257.4 billion in 2010 and NOK 205.9 billion in 2009. Both the 25% increase from 2009 to 2010 and the 24% increase from 2010 to 2011 were mainly caused by higher liquid prices measured in NOK.

Operating expenses and selling, general and administrative expenses include field production costs, costs incurred for transport systems related to the company's share of oil and natural gas production, expenses relating to the sale and marketing of our products, such as business development costs, payroll expenses and employee benefits.

In 2011, operating expenses and selling, general and administrative expenses amounted to NOK 73.6 billion, an increase of NOK 4.8 billion over 2010 when operating expenses and selling, general and administrative expenses were NOK 68.8 billion. The 7% increase reflects mainly the higher activity level in 2011 related to start-up and ramp-up of production on various fields, increased transportation and processing costs, and increased ownership shares. Also, changes in removal estimates, higher tariffs and royalties paid and increased business development costs added to the increase in expenses.

In 2010, operating expenses and selling, general and administrative expenses amounted to NOK 68.8 billion, an increase of NOK 1.5 billion over 2009 when operating expenses were NOK 67.3 billion. The 2% increase was mainly attributable to higher operating costs related to preparation for start up on new fields, and a provision for an onerous contract in 2010. The increase was partly offset by lower transportation costs because of reduced production, cost reductions from cost saving activities and a reversal of a provision for an onerous contract relating to Cove Point terminal.

Depreciation, amortisation and net impairment losses includes depreciation of production installations and transport systems, depletion of fields in production, amortisation of intangible assets and depreciation of capitalised exploration expenditure. It also includes impairment of property, plant and equipent and reversals of impairments. These total expenses amounted to NOK 51.4 billion in 2011, compared with NOK 50.7 billion in 2010 and NOK 53.8 billion in 2009. Included in these totals were net impairment losses of NOK 2.0 billion for 2011, NOK 4.8 billion for 2010 and NOK 7.2 billion for 2009.

Depreciation, amortisation and net impairment losses increased by 1% in 2011 compared to 2010 mainly because of higher depreciation from new fields and assets coming on stream, the impact on depreciation from revisions of removal and abandonment estimates. The increase was partly offset by the impact of lower production, increased reserve estimates and lower net impairment losses. The 6% decrease in depreciation, amortisation and net impairment losses in 2010 compared with 2009 was mainly due to lower impairment losses in 2010 and lower entitlement volumes.

Depreciation, amortisation and net impairment losses	Year ended 31 December				
(in NOK billion)	**2011**	2010 (restated)	2009 (restated)	11-10 change	10-09 change
Ordinary depreciation	**50.1**	45.7	46.4	10 %	(2 %)
Amortisation of intangible assets	**0.1**	0.2	0.1	(44 %)	40 %
Impairments	**4.5**	4.7	8.2	5 %	(43 %)
Reversal of impairments	**(3.3)**	0.1	(2.0)	<(100 %)	<(100 %)
Impairment of intangible assets	**0.0**	0.0	1.0	0 %	(100 %)
Depreciation, amortisation and net impairment losses	**51.4**	50.7	53.8	1 %	(6 %)

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

	For the year ended 31 December				
Exploration Expenses (in NOK billion)	**2011**	2010 (restated)	2009 (restated)	11-10 Change	10-09 Change
Exploration expenditure (activity)	**18.8**	16.8	16.9	12 %	(1 %)
Expensed, previously capitalised exploration expenditure	**1.8**	2.6	1.6	(30 %)	66 %
Capitalised share of current periods exploration activity	**(6.4)**	(3.9)	(7.2)	64 %	(45 %)
Impairment	**1.6**	1.9	5.4	(19 %)	(64 %)
Reversal of impairment	**(1.9)**	(1.6)	0.0	14 %	0 %
Exploration Expenses	**13.8**	15.8	16.7	(12 %)	(5 %)

The exploration expenses consist of the expensed portion of our exploration expenditure and impairment of exploration expenditure capitalised in previous years. In 2011, the exploration expenses were NOK 13.8 billion, a 12% decrease since 2010, when exploration expenses were NOK 15.8 billion. Exploration expenses were NOK 16.7 billion in 2009.

Exploration expenses decreased by 12% in 2011 compared to 2010, mainly because successful drilling resulted in a higher portion of exploration expenditures being capitalised, and because a lower portion of exploration expenditure capitalised in previous years was expensed in 2011 compared to 2010. The 5% decrease in exploration expenses from 2009 to 2010 was mainly due to lower drilling activity and a smaller proportion of exploration expenditure capitalised in previous years being impaired. The decrease was partly offset by higher oil sands delineation drilling expenses, higher seismic expenditures and higher pre-sanctioning costs.

In 2011 Statoil completed 41 **exploration and appraisal wells**, 25 on the NCS and 16 internationally. A total of 22 wells were announced as discoveries in the period, 17 on the NCS and five internationally. In 2010, a total of 35 exploration and appraisal wells were completed, 17 on the NCS and 18 internationally. A total of 19 wells were announced as discoveries in the period, 12 on the NCS and seven internationally. In addition, four exploration extension wells were completed on the NCS in 2010, three of which were announced as discoveries. In 2009, a total of 68 exploration and appraisal wells and two exploration extension wells were completed, 41 on the NCS and 29 internationally. Thirty-eight exploration and appraisal wells and two exploration extension wells were declared as discoveries in the period.