FACTS

THE NORWEGIAN PETROLEUM SECTOR

2010

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Foreword by the Minister of Petroleum and Energy Terje Riis-Johansen

As we now embark upon a new decade, we do so with the sense that we are entering a new era and a new energy reality. At the same time, it is tempting to pause, take stock and sum up the past as we pass new milestones. For nearly 40 years, the petroleum activities and the revenues they have generated have contributed to growth, employment, technological development and social welfare at a pace and scope that would not otherwise have been possible. We have every reason to be both proud and grateful.

Even more important, though, from our vantage point in 2010, is to look ahead. The future development of the Norwegian society will continue to be inextricably tied to our petroleum activities. The next 40 years will be at least as challenging – and just as crucial – as the years that are now behind us.

So far, we have produced just under forty per cent of the estimated resources on our continental shelf. Oil production has gradually declined in recent years, and is now considerably lower than in the peak year, 2001. This is a natural consequence of the maturing of our large fields. Determined efforts are needed now to stem annual declines in production. We have been unable to offset the production decline from existing fields with resources produced from new discoveries.

On the other hand, gas production has flourished in the last decade. Fields such as Ormen Lange and Snøhvit have increased our gas exports. We have also established a robust, comprehensive infrastructure for gas export that will serve us well for many decades to come.

The energy world as we know it is constantly changing and developing. The global financial crisis has led to weaker demand for gas while, at the same time, supplies have grown. In the USA, gas production from new sources has shown surprising growth, and huge volumes of LNG are flowing from new facilities in the Middle East. We see a challenging situation in the gas market for the next few years. Over the longer term, we expect a more balanced gas market as demand recovers.

On the Norwegian shelf, we want more discoveries, both in mature and new areas. The only way to achieve this is to explore. The objective of the APA scheme is to promote more activity in the mature areas of the Norwegian shelf. Good and regular access to exploration acreage is necessary to ensure continued activity on the Norwegian shelf. In 2010, we will implement the largest expansion of the APA area in terms of blocks available for award in predefined areas since the scheme was introduced in 2003. In mature areas, we will also facilitate exploration through regular awards.

We face exciting years on a number of fronts. We plan to prepare a new White Paper on petroleum, and the comprehensive management plan for Lofoten and the Barents Sea will be updated.

The challenges we face also run along multiple lines. We must exploit more of the resources which are still in the ground to maintain high activity on the Norwegian shelf. Improved recovery and vigorous exploration are both important components in sustaining this activity in a long-term perspective. At the same time, we recognise that climate change means we must cut emissions of greenhouse gases. With our petroleum expertise, Norway must naturally play an important role by contributing to development of technology that can reduce global greenhouse gas emissions. In our continuing efforts, we must work along two parallel lines of commitment: That we will continue to deliver energy that is as environmentally friendly as possible, and that we will contribute towards reducing greenhouse gas emissions. I am confident that we will succeed!

When this edition of Facts was printed, Norway and Russia have just agreed on a solution to the maritime delimitation in the Barents Sea and the Arctic Ocean. The signing of the treaty and ratification thereof is not yet carried out. This is very positive and provides a solid foundation for increased activity and cooperation between Norway and Russia on the petroleum sector, on the authority level as well as between industrial actors. An updated map showing the delimitation line is not yet available. This will be included in next year's edition.

Facts 2010 gives a broad overview of the Norwegian petroleum activities, covering most perspectives. I hope that this publication will provide useful information, both for those who are already familiar with the industry, as well as those who want to learn more about this important sector.

The Minister of Petroleum and Energy

Foreword by Director General Bente Nyland

2009 marked the 40th anniversary of the Ekofisk discovery and the 30th anniversary of Statfjord coming on stream. Twenty years ago, Ekofisk, Statfjord, Gullfaks and Oseberg accounted for almost three-quarters of all oil production. The situation in 2010 is more diverse, but the older fields still represent a large part of the production. One of the main challenges we face is that the installations on many of the larger fields are aging, which means that investment decisions, or the lack of such decisions, will greatly influence future recovery of resources on these fields. These decisions must be made in the next five to ten years to avoid loss of these resources. The role of the Norwegian Petroleum Directorate (NPD) is to be a driving force behind the companies, to ensure that the resources are converted into values for society.

The NPD declared in 2005 that it would be realistic, although ambitious, to assume that the oil reserves on the Norwegian shelf could be increased by 5 billion barrels during the period from 2005 to 2015. It was assumed that around 75 per cent of the increase would have to come from fields already in production. We are now halfway through the period, and we acknowledge that this can be a difficult goal to reach. This emphasises the need for considerably stronger effort on the part of the oil companies, especially licensees on producing fields, and where decline towards cessation has begun. The choice is between reinvesting some of the profits from these fields to further increase recovery, or settling for realising the planned production levels and shutting down when this has been achieved.

Based on existing plans, an average of about 54 per cent of the oil will be left underground. Even though Norwegian fields have a very high recovery factor for oil compared with

other countries, the NPD will be actively pushing to increase recovery in the coming years. This will require significant investments, with corresponding revenue potential. We are paying special attention to the plans for further development of the Ekofisk area and the Tampen area, where the largest time-critical resources are located.

It did not go unnoticed that the NPD decided not to award the prize for improved recovery in 2009, the IOR award. The NPD awards this prize for courage and commitment towards increased recovery beyond what is already in field production plans. We expect to be able to award this prize in 2010.

Much of the effort towards maintaining production and increasing reserves is linked to drilling production wells. The number of wells drilled has declined in a period when it should be increasing. In our view, one important reason for the higher than estimated production decline in the last decade is precisely because fewer production and injection wells have been drilled. In the short term, the NPD counts on more development wells being drilled to increase production. In the long term, other methods must also be used and the NPD will be a driving force behind this effort.

2009 experienced less production of liquids (oil, condensate and NGL) than 2008, while gas production set new records. In 2013, gas production will account for 50 per cent of the total Norwegian petroleum production.

As manager of Norway's petroleum resources, the NPD shall contribute to creating values for the Norwegian society. The decline in oil production cannot be stopped. Nature determines the volume of the resources, but human effort determines how much we can recover. Therefore, it is important to increase recovery from producing fields, thus slowing the overall decline in production. New discoveries are also an important factor for maintaining production.

A new record for exploration on the Norwegian shelf was set in 2009. 72 exploration wells (47 wildcat wells and 25 appraisal wells) were completed and 28 discoveries were made. Most of the discoveries were small, but many of them are close to fields in production. This means that they can come on stream quickly, thus contributing to future production from these fields. The discovery rate on the Norwegian shelf was high in 2009, about 60 per cent. This is to be expected, since we mostly explore in areas which have been extensively mapped in several phases. The last time new exploration areas were opened up on the Norwegian shelf was in 1994.

The Climate Cure 2020 project is a joint effort between several government bodies, led by the Norwegian Climate and Pollution Agency. Menus of measures that can be implemented to help reach the government's goal of reducing greenhouse gas emissions have been prepared. The NPD was responsible for the sector report for petroleum and the report on capture and storage of CO_2 (CCS). Among the initiatives considered for the petroleum sector are energy efficiency, electrification and CCS. The industry has already implemented a number of measures related to energy efficiency improvement, mostly because of the CO_2 tax introduced in 1991. We expect this work to continue.

In 1996, the Storting (Norwegian parliament) decided that land-based power, or electrification, should be considered for all new developments on the Norwegian shelf. This is followed up during the work on development plans for new fields. The NPD has taken the initiative to ensure that power from land is evaluated when considering major modifications on producing fields.

The NPD is currently mapping suitable storage areas for CO_2 on the Norwegian shelf, and a cooperation with the British authorities has been established to map the entire North Sea for storage options. CO_2 captured for storage can also constitute a resource, used for injection to increase oil recovery.

Director General

Content

1

THE PETROLEUM SECTOR – NORWAY'S LARGEST INDUSTRY

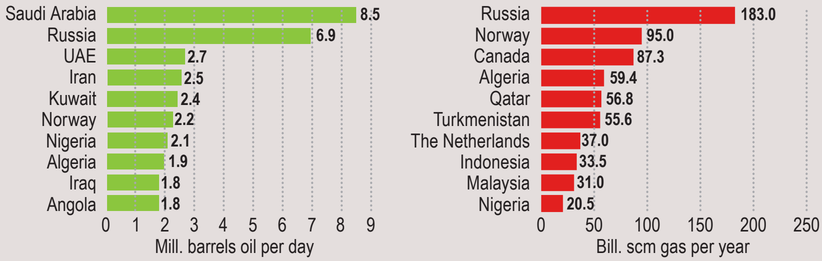


Figure 1.1 The largest oil exporters (including NGL/condensate) and gas exporters in 2008
(Source: KBC Market services/Cedigaz)

In the late 1950s, few people believed that the Norwegian continental shelf (NCS) might conceal rich oil and gas deposits. However, the discovery of gas at Groningen in the Netherlands in 1959 caused geologists to revise their thinking on the petroleum potential of the North Sea.

With the Ekofisk discovery in 1969, the Norwegian oil adventure commenced. Production from the Ekofisk field started on 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 65 fields in production on the NCS. In 2009, these fields produced 2.3 million barrels of oil per day (including NGL and condensate) and 102.7 billion standard cubic metres (scm) of gas, resulting in a total production of saleable petroleum of 238.6 million scm oil equivalents (o.e.). In 2008, Norway was ranked as the world's sixth largest oil exporter and the eleventh largest oil producer. In 2008, Norway was the second largest gas exporter in the world, and the fifth largest producer of gas.

The significance of the petroleum sector to the Norwegian society

Petroleum activities have contributed significantly to economic growth in Norway and to the financing of the Norwegian welfare state. Throughout nearly 40 years of business activities, the industry has created values of approximately NOK 8 000 billion in current terms. In 2009, the petroleum sector accounted for 22 per cent of national value creation. The value created by the petroleum industry is almost three times higher than inland based industries and around 22 times the total value creation of the primary industries.

Tax revenues levied on oil and gas companies together with net cash flow from direct ownership in fields and infrastructure (SDFI – the State's Direct Financial Interest), ensure that the State receives much of the value created from petroleum activities carried out in Norway. In the National budget for 2010, the State's net cash flow from the petroleum sector amounted to approximately 27 per cent of total revenues in 2009. The State's revenues from petroleum activities are allocated to a separate fund, the Government Pension Fund – Global. By the end of 2009, the value of this fund was NOK 2 640 billion.

The petroleum revenues are gradually phased into the economy to cover the structural, oil-corrected deficit in the fiscal budget. The funds are phased in approximately in step with the development in the expected real return of the Fund.

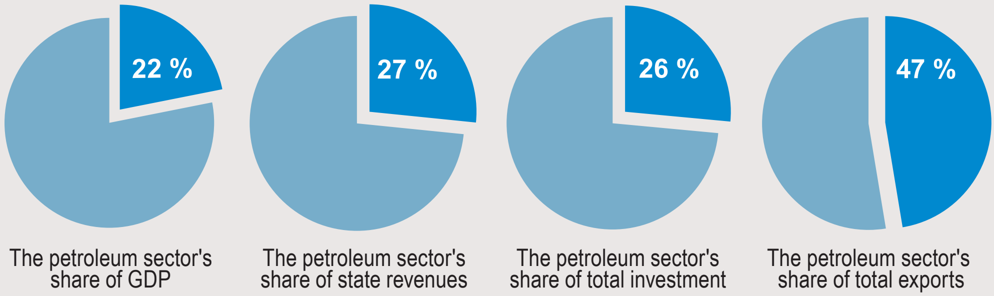


Figure 1.2 Macroeconomic indicators for the petroleum sector
(Source: Statistics Norway, Ministry of Finance)

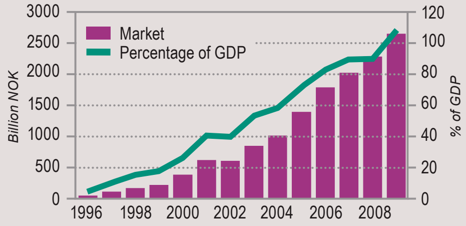


Figure 1.3 The size of the Government Pension Fund – Global at 31.12.2009 and as a share of GDP *(Statistics Norway and Norges Bank)*

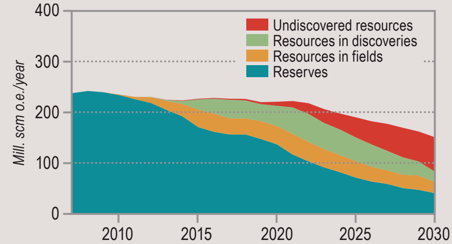


Figure 1.4 Production forecast *(Source: Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)*

In 2009, crude oil, natural gas and pipeline transport services accounted for nearly half of the value of Norway's exports. Measured in NOK, the value of petroleum exports was close to NOK 480 billion in 2009, 11 times higher than the export value of fish.

Since the petroleum industry started its activities on the NCS, enormous sums have been invested in exploration, field development, transport infrastructure and land facilities; at the end of 2009 about NOK 3 000 billion (current terms) had been invested. Investments in 2009 amounted to approximately NOK 136 billion, or 26 per cent of total real investments in Norway.

Future trends

We have produced about 40 per cent of the expected total recoverable resources on the NCS. The remaining resources represent a substantial potential of value creation for many years to come.

Figure 1.4 shows a production forecast for the NCS. It is based on the Norwegian Petroleum Directorate's estimate of recoverable petroleum resources and it is assumed that the authorities and the industry will implement the necessary measures to recover the remaining volumes.

Petroleum production is expected to remain steady over the next few years. The production of oil and other petroleum liquids will gradually decrease. Gas sale on the other hand is expected to increase and to reach a level between 110 to 130 billion scm within the next decade. From representing close to 43 per cent of the total Norwegian petroleum production in 2009, the share attributed to gas production will increase considerably in the future. In the longer term, the number and size of new discoveries will be a critical factor for the production level.

The investment level on the NCS has grown considerably in recent years, and is expected to stay high also in the years to come. Recent developments in the world economy contributed to a lower level of investments in 2009 than previously expected, but are still estimated to amount to approximately NOK 110 billion in 2010, excluding exploration costs. The high increase in investments seen the last years is explained by higher costs in the sector, together with a more mature shelf resulting in more complicated and expensive methods for exploiting the resources.

The oil price is a very important factor as regards to the activity level and revenues to the State. The price of oil has varied considerably the last 2-3 years years. In 2009 the trend was an increasing oil price throughout the year; from approximately USD 40 per barrel at the beginning of the year, till about USD 80 per barrel at the start of 2010. Improving world economy, increasing demand for oil in growing economies coupled with production restrictions from OPEC were some of the factors contributing to the increasing oil price in 2009.

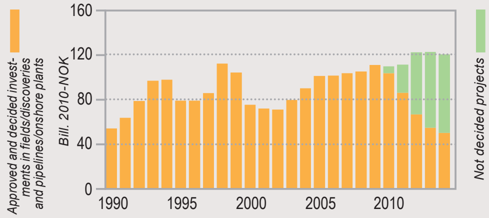


Figure 1.5 Historical investments (investments excl. exploration costs) *(Source: Norwegian Petroleum Directorate/ Ministry of Petroleum and Energy)*

2

ORGANISATION OF NORWEGIAN PETROLEUM ACTIVITY

The interest in exploring for oil on the Norwegian continental shelf began in the early 1960s. At that time there were no Norwegian oil companies, and very few Norwegian institutions, public or private, had any knowledge of petroleum-related activities. There was even a question as to whether the Norwegian continental shelf really held significant petroleum resources. Right from the start, national administration and control over the petroleum activities on the Norwegian continental shelf have been fundamental requirements. The challenge facing Norway in developing its petroleum activities was to establish a system of managing the petroleum resources – a system that would maximise the value for Norway as a whole.

In the beginning, the Norwegian government selected a model in which foreign companies carried out the petroleum activities on the Norwegian continental shelf. Over time, the Norwegian involvement was strengthened through the participation of Norsk Hydro, and by the creation of a wholly owned state oil company, Statoil, in 1972. A private Norwegian company, Saga Petroleum, was also established. Saga was in 1999 acquired by Norsk Hydro. In 2007, Norsk Hydro's oil and gas activities merged with Statoil, and the new company was named StatoilHydro ASA. From November 1st 2009 the company was renamed Statoil ASA. The cooperation and competition between the various companies on the Norwegian continental shelf have been crucial, as the companies have all possessed different technical, organisational and commercial expertise. This policy has contributed to ensuring that Norway today has its own oil companies and a competitive supplier industry, and that the nation has secured substantial revenues from the sector.

The current resource management model

In order for oil companies to make rational investment decisions, the framework conditions must be predictable and transparent. The organisation of the activities and the division of roles and responsibilities shall ensure that important social considerations are safeguarded and that the value created from the activities benefits society as a whole. At the same time, consideration for the external environment, health, working environment and safety plays an important role.[1]

Norwegian and international oil companies are responsible for the actual petroleum activities on the Norwegian continental shelf. Competition between oil companies yields the best result when it comes to maximising the value of the petroleum resources. At the same time, it is important that the authorities can understand and evaluate the decisions made by the companies. Therefore, Norway has established a system whereby oil companies supply the ideas and carry out the technical work required to recover the resources, but their activities also require approval by the authorities. The approval of the authorities is required in all stages of the petroleum activities, from the awarding of the exploration and production license, in connection with seismic surveys, exploration drilling[2], plans for development and operation[3] and decommissioning plans[4] for fields.

For the oil companies to maximise the values on the Norwegian continental shelf, a framework must be in place which provides the petroleum industry with incentives to fulfil

1 Environmental considerations in the petroleum activities are addressed in Chapter 9.

2 Ref. Chapter 4.

3 Chapter 5 addresses development and operation, while gas management is discussed in Chapter 6.

4 More on decommissioning after production is concluded in Chapter 7.

the state's objectives while at the same time meeting their own goals, which is to maximise their profits. Through the petroleum taxation system and the State's Direct Financial Interest (SDFI), the state receives a substantial portion of the revenues from the petroleum activities. This system is designed so that, if the oil companies do not make money, neither will the Norwegian State. In this manner, all players in the Norwegian petroleum sector have a common interest in ensuring that production of the Norwegian petroleum resources creates the greatest possible values.

Cooperation and competition

While competition is desirable, cooperation between the players in the petroleum industry is also beneficial. Therefore, the main rule is that the authorities award production licences to a group of companies instead of one company alone, normally on the basis of applications from oil companies in connection with licensing rounds.[5] The most important award criteria include understanding of the geology, technical expertise, financial strength and the experience the authorities have had with the specific oil company. Based on the applications, the Ministry of Petroleum and Energy establishes a licensee group and appoints an operator. In this group, the oil companies exchange ideas and experience, and share the costs and revenues associated with the production licence. The companies compete, but must also cooperate to maximise the value in the production licence they have been awarded. Under this system, expertise and experience are gathered from a number of companies from all over the world. The licensee group also functions as an internal control system within the production licence, where each licensee is responsible for monitoring the work of the operator.

The petroleum sector is driven by technological innovation. Maximising the values on the Norwegian continental shelf requires that oil companies constantly apply the best available technology, and that they carry out the necessary research and development. Therefore, the Norwegian authorities have established an environment that promotes technological development. Today there is close collaboration between oil companies, research institutes, the supply industry and the authorities when it comes to technology and research.[6]

National organisation of the petroleum sector

The Storting

The Storting (Norwegian parliament), establishes the framework for the Norwegian petroleum activities. The methods used include passing legislation. The opening of new areas for petroleum activities, major development projects or matters of great public importance must be discussed by the Storting. The Storting also supervises the Government and the public administration.

The Government

The government holds the executive power over petroleum policy and is responsible vis-à-vis the Storting for this policy. In applying the policy, the government is supported by the ministries and subordinate directorates and agencies. The responsibility for executing the various roles within the petroleum policy is shared as follows:

5 *Ref. Chapter 3.*

6 *A more detailed discussion of exploration policy can be found in Chapter 4.*

- The Ministry of Petroleum and Energy – responsible for resource management and for the sector as a whole
- The Ministry of Labour – responsible for health, the working environment and safety
- The Ministry of Finance – responsible for state revenues
- The Ministry of Fisheries and Coastal Affairs – responsible for oil spill contingency measures
- The Ministry of the Environment – responsible for the external environment.

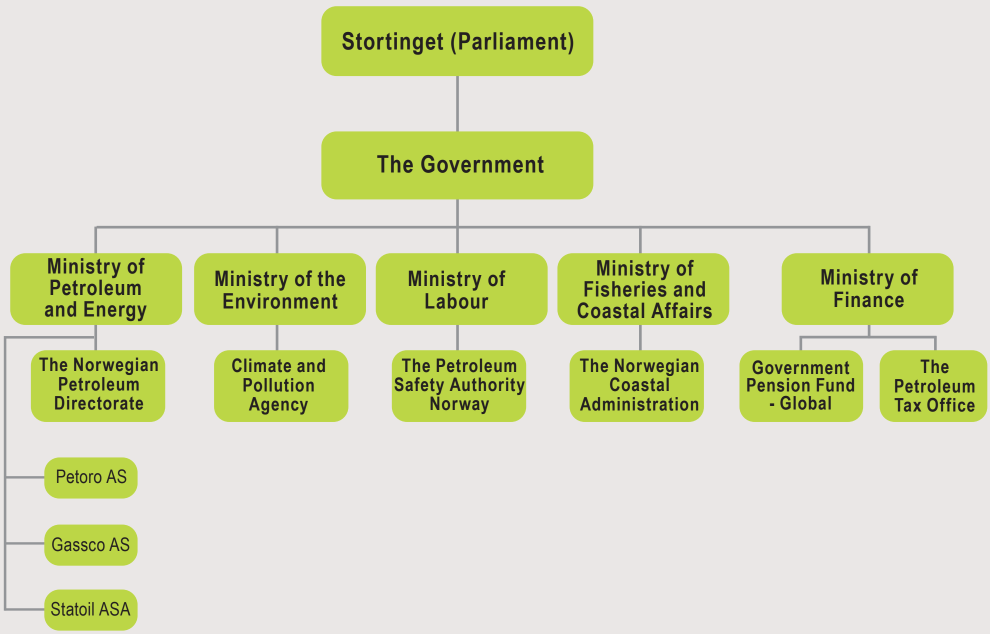


Figure 2.1 State organisation of the petroleum sector
(Source: Norwegian Ficsal Budget)

More on the organisation of the petroleum sector

THE MINISTRY OF PETROLEUM AND ENERGY

The Ministry of Petroleum and Energy holds the overall responsibility for management of petroleum resources on the Norwegian continental shelf. This includes ensuring that the petroleum activities are carried out in accordance with the guidelines given by the Storting and the government. In addition, the Ministry has a particular responsibility for supervising the state-owned corporations, Petoro AS and Gassco AS, as well as the oil company in which the state holds a majority interest, Statoil ASA.

The Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate (NPD) is administratively subordinate to the Ministry of Petroleum and Energy. The NPD plays a key role in petroleum resource management, and is an advisory body for the Ministry of Petroleum and Energy. The NPD exercises authority in connection with exploration for and production of petroleum deposits on the Norwegian continental shelf, including statuary powers and to make decisions based on the rules regulations governing the petroleum activities.

Petoro AS

Petoro AS is a state-owned corporation which is responsible for the management of the State's Direct Financial Interest (SDFI) on behalf of the state.

Gassco AS

Gassco AS is a state-owned company responsible for the transport of natural gas from the Norwegian continental shelf. The company is the operator of Gassled, although it has no ownership interest in the company. Gassco AS handles this operatorship in a manner that is neutral for all owners and users.

Statoil ASA

Statoil ASA is an international energy company with representation in 41 countries. The company is listed on the Oslo and New York stock exchanges. The state owns 67 per cent of the company's shares.

More on the national organisation of the petroleum sector

THE MINISTRY OF LABOUR
The Ministry of Labour holds the overall responsibility for the working environment and for safety and emergency preparedness measures in relation to the petroleum sector.

The Petroleum Safety Authority Norway
The Petroleum Safety Authority Norway has regulatory responsibility for safety, contingency measures and the work environment in the petroleum sector.

The Petroleum Safety Authority Norway is responsible for technical and operational safety, including emergency preparedness and the working environment in the petroleum sector.

THE MINISTRY OF FINANCE
The Ministry of Finance holds the overall responsibility for ensuring that the state collects taxes, fees (corporate tax, special petroleum tax, CO_2 tax and NO_x tax) from the petroleum sector. It also holds the overall responsibility for the management of the Government Pension Fund.

The Petroleum Tax Office
The Petroleum Tax Office is part of the Norwegian Tax Administration, which is subordinate to the Ministry of Finance. The main function of the Petroleum Tax Office is to ensure correct assessment and collection of the taxes and fees that have been determined by the political authorities.

The Government Pension Fund – Global
The Ministry of Finance is responsible for managing the Government Pension Fund - Global. Responsibility for operational administration has been delegated to Norges Bank.

THE MINISTRY OF FISHERIES AND COASTAL AFFAIRS
The Ministry of Fisheries and Coastal Affairs is responsible for maintaining adequate contingency measures against acute pollution in Norwegian waters.

The Norwegian Coastal Administration
The Coastal Administration is responsible for national oil spill contingency measures.

THE MINISTRY OF THE ENVIRONMENT
The Ministry of the Environment holds the overall responsibility for environmental protection and management of the Norwegian external environment.

The Climate and Pollution Agency
The responsibilities of the Norwegian Pollution Control Authority include enforcing the Pollution Control Act. Another key task is to provide the Ministry of the Environment with advice, guidelines and technical documentation.

3

GOVERNMENT PETROLEUM REVENUES

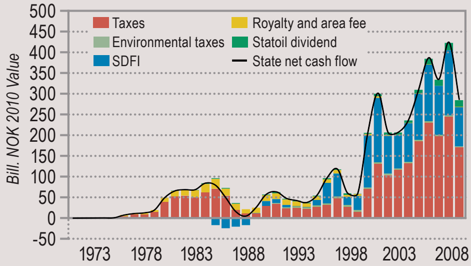


Figure 3.1 The net government cash flow from petroleum activities *(Source: Norwegian Public Accounts 2009 and account figures for SDFI)*

Direct taxes:	165.2
Environmental taxes and area fee:	3.7
SDFI:	95.3*
Statoil dividend:	15.5**
Total:	279.8

* SDFI annual accounts 2009

** Dividend for 2008 paid in 2009

Figure 3.2 The net government cash flow from petroleum activities 2009 (bill. NOK) *(Source: National Budget 2010 and account figures for SDFI)*

The Government receives significant revenues from petroleum activities. In 2009, approximately 27 per cent of total state revenues came from this sector. Figure 3.1 shows that income from this sector has been consistently high in recent years, with 2006 yielding extraordinarily high income to the State. In the 2010 national budget the value of the remaining petroleum resources on the Norwegian continental shelf is estimated at NOK 4 744 billion.

The Government receives a large share of the value created through:

- Taxation of oil and gas activities
- Direct ownership in fields and infrastructure (through the State's Direct Financial Interest, SDFI)
- Charges/fees
- Dividends from ownership in Statoil

Norway has implemented a specific fiscal system designed to secure state revenues from petroleum activities. The main rationale for the system is the extraordinary returns associated with production of petroleum resources. The specific fiscal system is explained by the objective that all petroleum resources shall benefit the societty as a whole, and that oil and gas companies are allowed to exploit a valuable and scarce resource.

The petroleum tax system

The petroleum tax system is based on Norwegian regulations for ordinary corporation tax. Due to the extraordinary profitability associated with production of petroleum resources, a special tax is also levied on the income from these activities. The ordinary tax rate is the same as for land activities, 28 per cent, whilst the special tax rate is 50 per cent. When calculating taxable income for both ordinary and special taxes, investments are subject to depreciation on a linear basis over six years from the date an investment is made. Companies may deduct all relevant expenses, including exploration, research and development, financial, operating and removal expenses (see Figure 3.3). Consolidation between fields is permitted. In order to shield the normal return from the special tax, an extra deduction, called the uplift, is allowed in the calculation base for special tax. This amounts to 30 per cent of the investments (7.5 per cent per annum for four years from the year an investment is made).

Companies that are not in tax position may carry forward their losses and the uplift with interest. An application may also be made for refund of the fiscal value of exploration costs in the companies' tax returns.

The petroleum tax system has been designed to be neutral, so that an investment project that is profitable for an investor before tax will also be profitable after tax. This allows combining the requirement for significant revenues to the society with the requirement for sufficient profitability for the companies to develop profitable projects.

Environmental Taxes

The area fee is intended to be an instrument that contributes to efficient exploration of awarded acreage so that potential resources are produced as quickly as possible within a prudent financial framework, as well as to extend the lifetime of existing fields.

Other taxes

Important auxiliary taxes linked to petroleum activities are the carbon dioxide tax, the NO_x tax and the area fee.

The CO_2 tax was introduced in 1991 and is an instrument for reducing CO_2 emissions from the petroleum sector. CO_2 tax is levied at a rate per standard cubic metre (scm) of gas burned or directly released and per litre of petroleum burned.

Operating income (norm price)
- Operating expenses
- Linear depreciation for investments (6 years)
- Exploration expenses, R&D and decommisioning
- CO_2-tax, NO_X-tax and area fee
- Net financial costs

= Corporation tax base (tax rate: 28 %)
– Uplift (7,5 % of investment for 4 years)

= Special tax base (tax rate: 50 %)

Figure 3.3 Calculation of petroleum tax
(Source: Ministry of Petroleum and Energy)

The rate for 2010 is NOK 0.47 per litre of petroleum or per scm of gas.

Pursuant to the Gothenburg Protocol of 1999, Norway has an obligation to reduce annual emissions of nitrogen oxides (NO_x). In order to fulfil this obligation, the NO_x tax was introduced from 1 January 2007. For 2010, the tax is NOK 16.14 per kg of NO_x.

Norm prices

Most oil companies conducting business on the Norwegian continental shelf are part of corporations with a diversified global business portfolio. Produced petroleum is therefore largely sold to associated companies.

It can be a challenging task for the petroleum tax authorities to assess whether prices agreed between two associated companies are equivalent to what two independent parties would have agreed upon jointly for each individual sale. In order to avoid this problem, Section 4 of the Petroleum Tax Act states that norm prices may be stipulated and used in the calculation of taxable income. The methods for stipulation and use of norm prices are described in separate regulations.

The norm price is set by the Petroleum Price Council (PPR), and should reflect the price paid for petroleum traded between independent parties. As a rule, the norm price is stipulated each month and for each field. The PPR meets each quarter to stipulate prices for the previous quarter. The prices are based on information from and meetings with the operating companies before the final norm price is stipulated. Decisions may be appealed to the Ministry of Petroleum and Energy within 30 days. When the PPR does not find it appropriate to stipulate a norm price, the actual achieved sales price will be used as the basis for taxation. This applies to certain crude oils and NGL. The actual sales price is used as a basis for gas.

SDFI

The State's Direct Financial Interest (SDFI) is an important source of state revenues, in addition to taxes, fees and dividends from its ownership in Statoil. SDFI is an arrangement in which the State owns interests in a number of oil and gas fields, pipelines and onshore facilities. The Government take is decided when production licences for oil and gas fields are awarded and the size of the State interest varies from field to field. As one of several owners, the State pays its share of investments and costs, and receives a corresponding share of the income from the production licence. SDFI was established on 1 January 1985. Prior to this Statoil alone, at the time a fully state-owned company, was responsible for the State's ownership holdings in production licences. In 1985, Statoil's participation was split into one direct financial share for the State (SDFI) and one for Statoil. When Statoil was partially privatised on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-owned trust company, Petoro. As of 1 January 2010 the State had direct financial interests in 137 production licences and 14 joint ventures for pipelines and onshore facilities.

Statoil dividend

The State owns 67 per cent of the shares in Statoil. As an owner in Statoil, the State receives dividend which forms a part of the State's revenues from the petroleum sector.

EITI

The Extractive Industries Transparency Initiative is an international initiative whose purpose is to strengthen good governance in resource-rich countries through the publication of revenues from oil, gas and mining companies to the state.The purpose is to make information about the revenue streams from this sector more readily available. Norway implemented EITI in the fall of 2007.

4

EXPLORATION ACTIVITIES

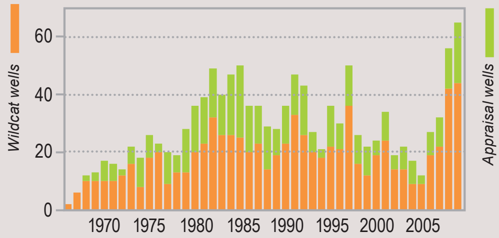


Figure 4.1 Exploration wells spudded on the NCS 1966-2009

(Source: Norwegian Petroleum Directorate)

Exploring for and proving undiscovered resources is a prerequisite for recovering the petroleum resources on the Norwegian continental shelf. Exploration activities are an important indicator of future production. Typically, it takes several years from a decision to begin exploring for resources until any discoveries can be put into production. 10-15 years is not unusual. The formulation of exploration policy is hence an important aspect of long-term Norwegian resource management.

Recent years have shown a decline in oil production on the Norwegian shelf. For the authorities, it is important that Norwegian exploration policy provides for rapid and efficient identification of new resources to offset declining production. It is the companies that undertake the exploration and the proving of new resources. Exploration policy is therefore designed to ensure that the Norwegian continental shelf is attractive for established and new players that can contribute to efficient exploration. The government will give the companies access to attractive exploration acreage. The exploration acreage should offer possibilities in both mature and new, less explored areas which could hold resources.

The exploration activities have increased substantially in 2007 after a period of slow activity. A total of 32 exploration wells were spudded in 2007, including 20 appraisal wells. Twelve discoveries were made. In 2008 56 exploration wells were spudded. Of these, 41 were wildcat wells and 15 were appraisal wells. Twenty-five discoveries were made. A new record was set in 2009 with 65 wells spudded. 44 of these wells were wildcat wells and 21 were appraisal wells. Record high 28 discoveries were made. Continued exploration drilling in frontier areas in the Norwegian Sea and the Barents Sea will be important for the mapping and evaluation of the resource potential in these areas.

A fundamental precondition for petroleum activities on the Norwegian continental shelf is the coexistence of the oil industry and other users of the sea and land areas affected by such activities. This precondition is also important in licensing policy. This policy places great emphasis on safeguarding the interests of all users of the marine areas, both when opening up new areas, in the announcement of licensing rounds and in the award of production licences.

The licensing system

The Petroleum Act (Act 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis for the licensing system which regulates Norwegian petroleum activities. The Act and its appurtenant regulations authorise the award of licences to explore for, produce and transport petroleum, etc.

The Petroleum Act establishes that the Norwegian State has proprietary rights to subsea petroleum deposits on the Norwegian continental shelf. Before permission for exploration drilling and production (a production licence) can be granted, the area in question must have been opened up for petroleum activities. In connection with this, an impact assessment covering such aspects as the environmental, economic and social effects of such activities on other industries and adjacent regions, must be prepared.

Production licences are normally awarded through licensing rounds. The government announces a certain number of blocks for which an application for a production licence may be made. Applicants may apply individually or in groups. Production licences are awarded on the basis of impartial, objective, non-discriminatory and published criteria. On the basis of the applications received, the Ministry of Petroleum and Energy puts together a group of companies for each licence or can make adjustments to a group which has submitted a joint application. The Ministry of Petroleum and Energy appoints an operator for this partnership, who is responsible for carrying out the day-to-day activities under the terms of the licence.

The production licence regulates the rights and obligations of licensees in relation to the state and supplements the provisions of the Petroleum Act

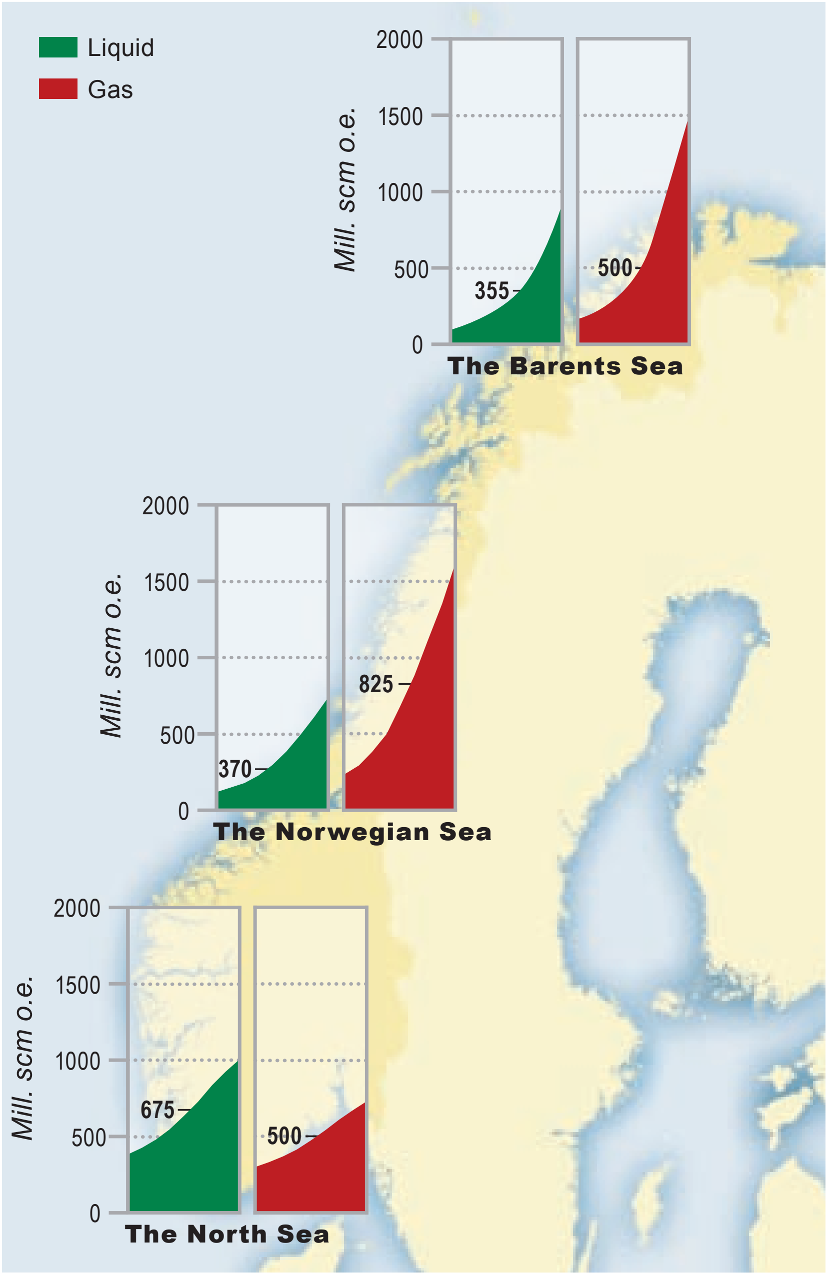


Figure 4.2 Undiscovered resources distributed by area. The number in each column indicates expected recoverable volume while the uncertainty in the estimate is shown by the slanted line, low estimate on the left, high estimate on the right *(Source: Norwegian Petroleum Directorate)*

and specifies detailed terms for each licence. The licence provides an exclusive right for exploration, exploration drilling and the production of petroleum within the geographical area specified in the production licence. Ownership of the petroleum produced rests with the licensees.

The production licence is awarded for an initial period (the exploration period), which can last up to ten years. A specified work commitment must be met during this period, including geological/geophysical preparatory work and/or exploration drilling. Providing that all the licensees agree, a licence can be relinquished once the work commitment has been fulfilled.

Mature and frontier areas

The parts of the Norwegian continental shelf that the Norwegian Parliament (Storting) has opened up for petroleum activities are the greater part of the North Sea, the Norwegian Sea and the southern Barents Sea. The Norwegian Petroleum Directorate's estimate of undiscovered resources in the areas on the continental shelf totals 3.3 billion standard cubic metres (scm) of recoverable oil equivalents. The resources are divided more or less equally between the three regions, with 35 per cent in the North Sea, 35 per cent in the Norwegian Sea and 30 per cent in the Barents Sea (see Figure 4.2). Depending on the degree of maturity of the different areas, there is some variation in the types of challenges involved in realising the commercial potential of the undiscovered resources on the Norwegian continental shelf.

Characteristics of mature areas include familiar geology, fewer technological challenges and well-developed or planned infrastructure. The discovery rate is high, but major new discoveries are less likely. There have been petroleum activities in parts of the mature area of the continental shelf for nearly 40 years. This means that the geology in these areas is well documented, and the infrastructure is for the most part highly developed.

Frontier areas are characterised by little knowledge of the geology, significant technical challenges and lack of infrastructure. The uncertainty surrounding exploration activity is greater here, but there is still the possibility of making substantial new discoveries in these areas. The companies allowed to explore in these areas must have broad-based experience, technical and geological expertise, and a solid financial base.

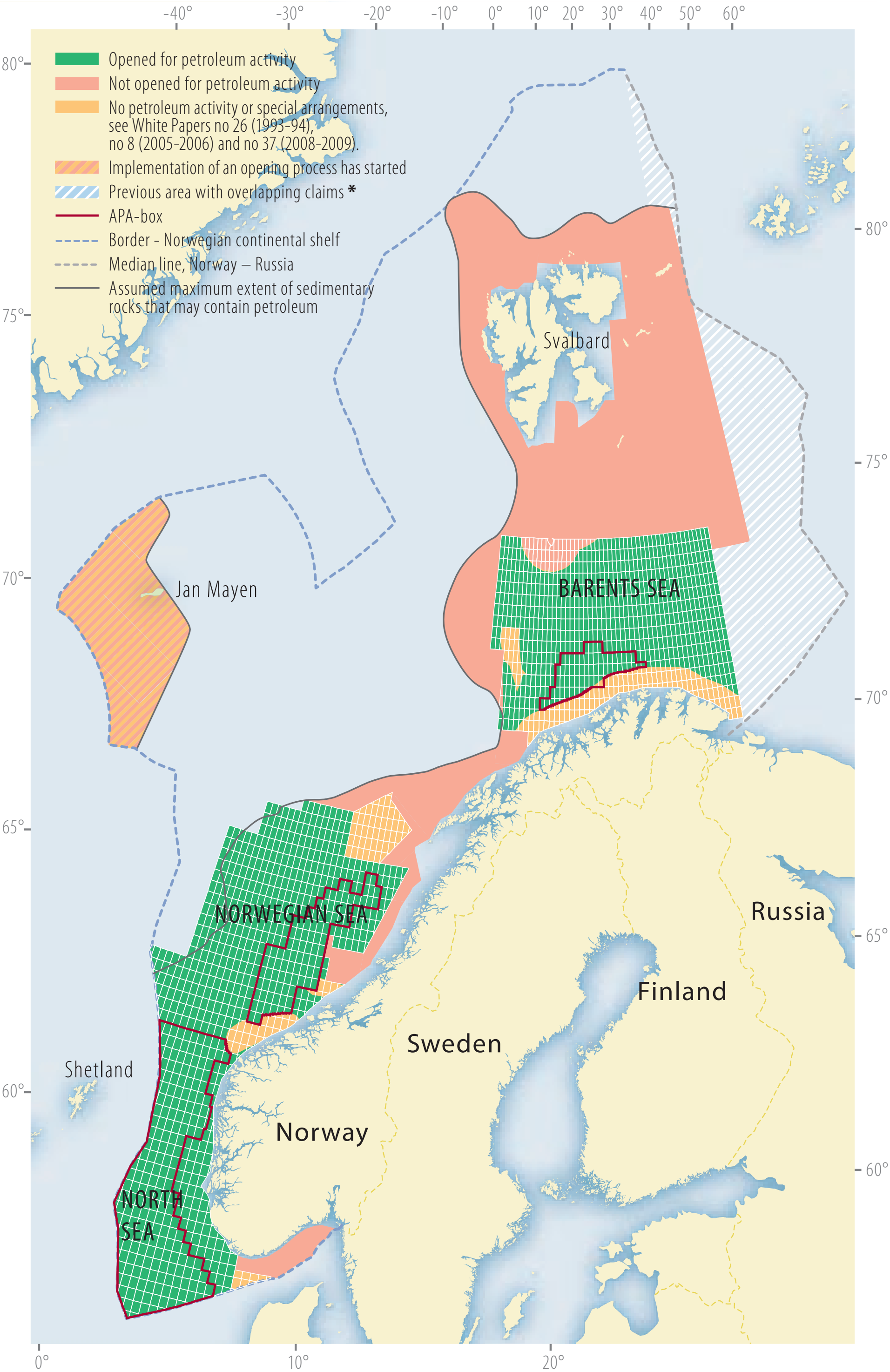
Exploration policy in mature and frontier areas

Mature areas

Petroleum activities on the Norwegian continental shelf started in the North Sea and have gradually moved northwards based on the principle of gradual opening of areas. Consequently, large portions of the North Sea are now considered to be mature from an exploration perspective. There has also been considerable exploration of Haltenbanken in the Norwegian Sea, and many parts of this region are also considered mature. The most recent area to be considered mature is the area surrounding Snøhvit in the Barents Sea.

The overall infrastructure is generally highly developed in mature areas. Nevertheless, the lifetime of the existing infrastructure is limited and it is thus important to prove and recover the resources in these areas before the infrastructure is shut down. Otherwise, profitable resources may be left in the ground because the discoveries are too small to warrant a stand-alone development of infrastructure.

The authorities have determined that industry access to larger parts of the mature areas is important so that time-critical resources can be produced. It is also important that the areas awarded to the industry are explored quickly and efficiently. For this reason, the Government has implemented a policy shift in mature areas, introducing a scheme in 2003 for award of production licences in predefined areas (APA) in mature areas of the Norwegian continental shelf (Storting White Paper No. 38 (2003-2004) On the petroleum activities). The pre-



***** *According to a joint statement agreed upon by Norway and Russia in Oslo 27.04.2010, the two countries will as soon as possible enter into an agreement regarding the maritime delimitation in this area in accordance with the recommendation of both countries` delegations for negotiation. The final agreement must be ratified by the Russian Duma and the Norwegian Storting before it enters into force.*

Figure 4.3 Area status on the Norwegian continental shelf
(Source: Norwegian Petroleum Directorate)

mise of this system is the designation of large, predefined exploration areas which encompass all mature areas on the Norwegian continental shelf. This area will be expanded, never curtailed, as new areas mature. The system entails a permanent annual cycle for licensing rounds in mature areas. Seven such licensing rounds have been carried out in mature areas to date (APA 2003 - 2009). APA 2010 was announced 19. February 2010 with an application deadline set to 15. September the same year. The APA-area was extended in the Norwegian Sea and the Barents Sea. Figure 4.3 show the areas announced for award in APA 2010.

Active exploration within licensed areas is important to the authorities. The areas awarded are tailored so that the companies will only get acreage where they have specific plans.

The work commitment assumed when companies are awarded new production licences consists of a set of activities and decisions. At each juncture, the company must decide whether it wants to implement new activities in the licence or relinquish the entire area. New companies that may have a different view on the prospectivity can then apply for these relinquished areas. This leads to a more rapid circulation of acreage and more efficient exploration of the mature areas. Upon expiration of the initial period, companies could previously retain as much as 50 per cent of the awarded area without an obligation to carry out any specific activity. Today, the general rule is that companies can only retain areas in which they plan to start production.

The area fee is also a policy instrument intended to help increase activity in the awarded areas. The idea behind the area fee is that no area fee shall be paid for areas where production or active exploration activity is taking place. The licensees pay no area fee during the initial period, in which exploration activity proceeds according to a compulsory work program. After the initial period, the licensees shall pay an annual fee to the state for each square kilometre of the area that is covered under a production licence. As of 1 January 2007, the area fee rules were updated to reinforce the function of the fee in overall resource management. Under the new rules, the companies shall pay NOK 30 000 per square kilometre for the first year, with the rate increasing to NOK 60 000 for the second year. From and including the third year, the companies pay the maximum fee rate, which is NOK 120 000 per square kilometre. The companies can achieve an exemption from the area fee if they submit a Plan for Development and Operation, a so-called PDO, to the Ministry of Petroleum and Energy. However, area fee exemptions are granted only for the areas that comprise the geographic extent of the resources, and for which a PDO has been submitted. The regulations also provide for area fee exemptions for two years if the companies drill a wildcat well in addition to the original work commitment.

Frontier areas

The areas currently considered to be frontier areas on the Norwegian continental shelf include major portions of the Barents Sea and the Norwegian Sea. In the Norwegian Sea, this applies particularly to deepwater regions and the northernmost areas. The coastal areas in the southern part of the Norwegian continental shelf are also relatively immature.

The 18th licensing round introduced a fundamental change in the rules for relinquishing area. The regulations that applied in mature areas were also applied to the immature areas. However, it is not expedient for all companies that receive production licenses in immature areas to submit a plan for development and operation by the end of the initial period. The main rule for relinquishment in these areas is therefore linked to delineation of resources proven through drilling. Furthermore, the same changes apply to immature areas as for mature areas with regards to tailoring the acreage to be awarded.

The announcement of the 19th licensing round in 2005 had particular focus on areas in the Barents Sea and the western part of the Norwegian Sea. These awards represented an important step in the

Figure 4.4 Norwegian and Russian part of the Barents Sea
(Source: Norwegian Petroleum Directorate)

exploration of these areas. The 20th licensing round was awarded in the spring of 2009 and had an emphasis on the same area as in the 19th licensing round. The nomination for the 21th licensing round is being processed with award of production licenses scheduled for the spring of 2011.

The gradual expansion of petroleum activities towards the vast frontier areas in the northern parts of the Norwegian continental shelf has necessitated a clarification of the terms and conditions for petroleum activities in these areas. Storting White Paper No. 8 (2005-2006) "Comprehensive management plan for the marine environment in the Barents Sea and the waters off Lofoten" (Comprehensive Management Plan), was submitted to the Storting in the spring of 2006. The comprehensive management plan presents the framework for the petroleum activities in these areas and provides guidelines as to where petroleum activities are permitted. Several programs have been initiated to gather more knowledge about the ocean areas involved, before the scheduled revision of the plan in 2010. One of these is a three-year program for geological mapping and acquisition of seismic data in Nordland VI, VII and Troms II, under the auspices of the Norwegian Petroleum Directorate. In 2007 and 2008, NOK 70 million and NOK 140 million respectively were allocated for this program, and in 2009 the budget was NOK 200 million.

The work on an integrated management plan for the Norwegian Sea commenced in the spring of 2007 and was submitted to the Storting in the spring of 2009 as Report No. 37 (2008-2009) to the Storting "Integrated Management of the Marine Environment of the Norwegian Sea". The integrated management plan for the Norwegian Sea establishes framework conditions that balance the interests of the fisheries, the petroleum industry and the shipping industry, as well as protecting the environment.

Unopened areas

There are still large parts of the Norwegian continental shelf which the Storting has not opened up for petroleum activities, including all of the northern Barents Sea, Troms II, Nordland VII, parts of Nordland VI, coastal regions off Nordland and Skagerrak. In April 2010, an agreement was

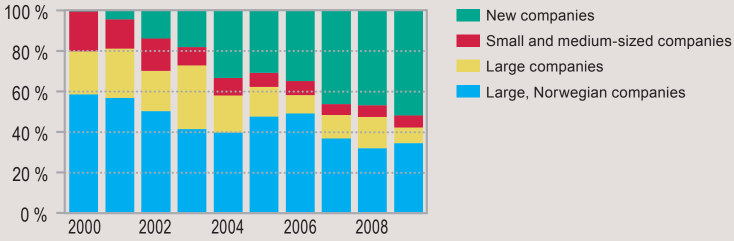


Figure 4.6 Exploration costs in production licences in the North Sea according to the size of the companies
(Source: Norwegian Petroleum Directorate)

made between Norway and Russia concerning the maritime delimitation in the Barents Sea and the Arctic Ocean.

The Storting must decide to open these areas for petroleum activities before they can be announced in a licensing round. Such a decision requires preparation of an impact assessment which examines factors including the economic, social and environmental effects such activities could have on other industries and the surrounding region. The question of whether or not to open these areas must also be submitted to local authorities and stakeholder organisations that may have a special interest in this matter.

Industry structure

Industry structure refers to the number and composition of oil companies involved in petroleum activities on the Norwegian continental shelf. The largest multinational players occupy a key place on the Norwegian continental shelf, which is a natural consequence of the fact that the shelf has been characterised by tasks that are historically large and complex in terms of the opportunity to realise substantial values. As the Norwegian continental shelf matures and the challenges there have changed and become more diverse, it has been important to adapt the player scenario to the altered situation. This has led to a focus in recent years on attracting competent new players onto the continental shelf.

Prequalification

In order to facilitate the entry of new players, Storting White Paper No. 39 (1999–2000) *On the oil and gas activities* introduced a system for prequalification of new operators and licensees. From the scheme's inception to January 2009, 48 new companies (at the time of writing) had been prequalified and still existing, or had become licensees on the Norwegian continental shelf. Additional companies are currently being evaluated or have indicated that they wish to become prequalified. Figure 4.5 shows prequalified and new companies since 2000.

Significant acreage and production licences have been awarded to these new players in the licensing rounds in mature areas. For the years 2007 and 2008 new players have accounted for more than 40 per cent of the exploration costs in the North Sea. (See Figure 4.6). The recent year the share has increased to 50 per cent.

So far most of the new companies have focussed on the mature areas in the North Sea and the Norwegian Sea. The last few rounds have shown increased interest on the part of the new entrants also in the Barents Sea. It is expected that more companies will take part in the licensing rounds in frontier areas as they expand their knowledge of the shelf and establish larger organisations in Norway.

More information on operators and licensees in production licences and fields on the Norwegian continental shelf can be obtained on the Norwegian Petroleum Directorate's website: www.npd.no.

Aker Exploration*	Det Norske	GdF	Nexen	Petoro	Skeie Energy
Aker Maritime*	Discover	Genesis*	Noble	Petro-Canada	Spring Energy
Altinex*	DNO	Hunt Oil	Noreco	Petrofac	Sumitomo
Anadarko	Dong	Idemitsu	North Energy	PGNiG	Talisman
BayernGas	E.ON Ruhrgas	Kerr McGee	OER*	Premier	VNG
BG Norge	Edison	Lasmo*	OMV	Repsol	Wintershall
Bridge Energy	Endeavour*	Lotos	Oranje Nassau	Revus*	4sea energy*
Centrica	Ener*	Lundin	PA Resources*	Rocksource	
CNR	Enterprise*	Marubeni	Paladin*	Sagex	
Concedo	Excel Expro	Mitsubishi	Pelican*	Serica	
Dana	Faroe	Mærsk	Perenco	Skagen 44	

* Not currently an independent company.

Figure 4.5 Prequalified/new companies since 2000 (As of 1st Quarter 2010)
(Source: Ministry of Petroleum and Energy)

5

DEVELOPMENT AND OPERATIONS

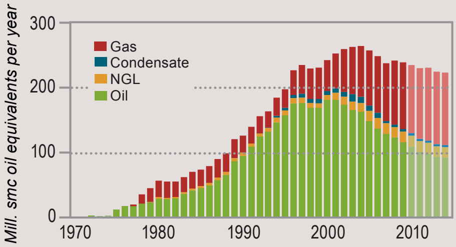


Figure 5.1 Historical production of oil and gas and production forecast for the next few years

(Source: Norwegian Petroleum Directorate)

In 2009, Norwegian oil and gas production totalled 238,6 million scm oil equivalents (o.e.), about 3 million o.e. less than the previous year. Of this, natural gas production accounted for 102,7 million scm o.e., oil production accounted for 115,5 million scm o.e., NGL accounted for 16 million scm o.e. and condensate accounted for 4,4 million scm o.e. While gas production grew last year, oil production fell. Gas sales reached more than 100 billion scm for the first time in 2009, with additional increases expected in the years to come. The natural gas share of total petroleum sales is expected to increase from 43 per cent in 2009 to 50 per cent in 2013. Figure 5.1 shows historical production of oil and gas, and expected production for the next few years.

In 2009, the authorities approved the Plans for Development and Operation (PDO) of Goliat, Oselvar and Troll Projects. In 2010, several new development plans may be submitted to the authorities for approval. The construction of a new living quarter on Ekofisk is one among the projects approved by the authorities in 2010. In addition, the development of the discoveries Gudrun, Marulk, Pi and Nemo could be approved by the authorities in 2010. The Trym development was approved by the authorities in March 2010.

Historic development

Production on the Norwegian continental shelf has been dominated by a few large fields. When the North Sea was opened up for petroleum activity, the most promising areas were explored first. This led to world-class discoveries which were then put into production, and were given names such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and still are, of great significance for the development of the petroleum activities. The large fields have contributed to the establishment of infrastructure that subsequent fields have been able to tie into. Production from several of these fields is declining, while several new, smaller fields have been developed, with the result that current production is distributed over a greater number of fields than previously. This development is to be expected. As the Norwegian petroleum industry has moved northwards, it has entered areas containing enormous gas resources. Consequently, a number of gas fields have been developed and a comprehensive gas transport infrastructure has been established, making it possible to develop additional gas resources. Development of the gas fields, combined with falling production from major oil fields, means that gas is becoming an ever more important component of Norway's petroleum production.

Effective production of petroleum resources

To protect society's interests in the development and operation of oil and gas fields, the authorities have established frameworks for these activities, which are intended to ensure that the companies make decisions that are also beneficial to society at large. It is important that these frameworks are predictable for the companies. Hence, the authorities have created a model that is characterised by both cooperation and competition between the players, with the intention of creating a climate for sound decisions that benefit both the companies and the rest of society.

Under the petroleum industry framework conditions, companies are obliged to carry out prudent development and operation of proven petroleum resources. This means that the companies are responsible for submitting and executing new projects, whereas the authorities give the final consent for implementation. When a new deposit is to be developed, the company must submit a plan for development and operation (PDO) for approval. An important part of the development plan is an impact assessment which interested parties are invited to comment upon

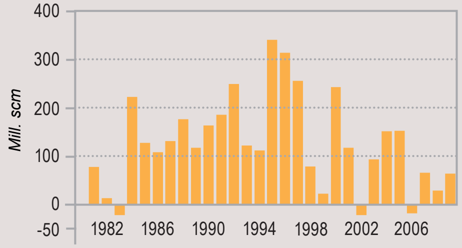


Figure 5.2 Gross reserve growth, oil 1981–2009

(Source: Norwegian Petroleum Directorate)

in a consultation process. The impact assessment describes the development's expected impact on the environment, fisheries and society in general. The authorities' consideration of this assessment and of the development plan ensures a prudent project in terms of resources, as well as acceptable consequences for other matters of public interest. The Ministry has now issued new and updated guidelines for plans for development and operation and plans for installation and operation. The main purpose of these updated guidelines is to clarify the regulations and the authorities' expectations for developments on the Norwegian shelf.

Development of proven petroleum resources is the basis for production and value creation from the petroleum industry today. The importance of exploiting the resources in the known areas is increasing. This constitutes an enormous potential that can generate significant value for society if exploited prudently. The Norwegian Petroleum Directorate has assessed this potential and has arrived at an objective for reserve growth on the Norwegian continental shelf of 800 million scm of oil before 2015. This is equivalent to twice the original oil resources in the Gullfaks field. This objective is a stretch target for both the industry and the authorities. If we are to realise this potential, we must increase recovery from fields in production, develop discoveries in the vicinity of existing infrastructure, prove and develop new resources and constantly operate the fields better and more cost-efficiently. Figure 5.2 shows annual growth of oil reserves in the period 1981–2009. The accounts for 2009 show a growth of 64 million scm of oil, included as new reserves. The 2008 accounts included a growth of 29 million scm of oil. The largest contribution to oil reserves in 2009 came from the Oseberg, Alvheim and Åsgard fields.

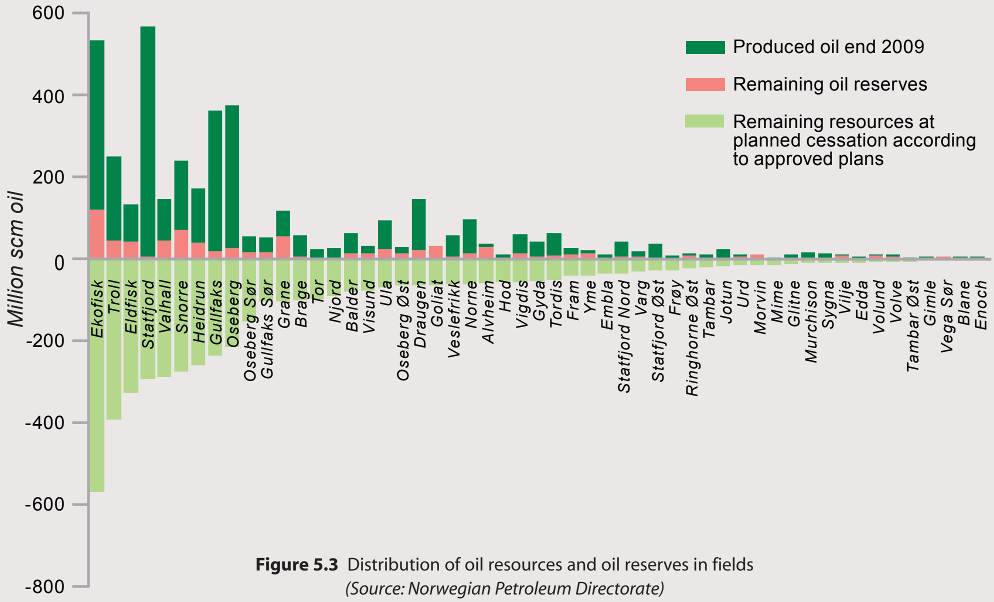


Figure 5.3 Distribution of oil resources and oil reserves in fields

(Source: Norwegian Petroleum Directorate)

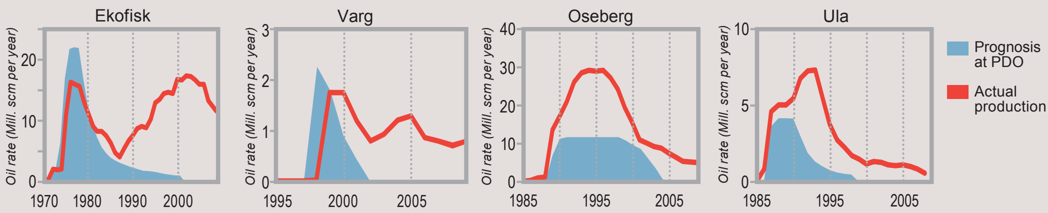


Figure 5.4 Production trends for Ekofisk, Varg, Oseberg and Ula
(Source: Norwegian Petroleum Directorate)

Increased recovery in mature areas

Parts of the Norwegian continental shelf are currently defined as mature areas. This term refers to areas that are characterised by familiar geology, well-developed infrastructure, falling production and increasing unit costs. There is still a considerable potential for value creation in these areas if we are able to increase the recovery rate in producing fields, streamline operations and explore for resources near existing infrastructure.

Figure 5.3 provides an overview of the total oil resources in producing fields. The resources can be divided into the following categories:

- produced quantities
- remaining reserves
- resources that will be left in the ground after planned shutdown

The figure shows that, on the basis of present plans, significant oil resources will remain in the ground after the planned shutdown of these fields. A number of measures must be implemented if we are to produce more of these resources. The measures can be divided into two main categories, where one covers measures to increase recovery and the other how to improve recovery through efficient operations.

Increased recovery

First and foremost, the licensees must invest in projects for improved recovery. Some examples are drilling more wells, measures to extract more from existing wells, injection into the reservoir to extract more petroleum and adaptations in process facilities. Such measures contribute to increasing the average recovery rate. In 1995, the average recovery rate for oil in producing fields was approximately 40 per cent - today it is 46 per cent. Development and use of new technology has played a very important role in increasing recovery, and it still does. For example, new technology makes it possible to drill wells and develop fields in ways which were not technically feasible in the past.

Figure 5.4 shows production trends for the Ekofisk, Varg, Oseberg and Ula fields. The figure shows that actual production from these fields has proved to differ greatly from the estimates made when the original development plans were submitted. Based on the original plans, these fields should now have been closed down. Due to efficient operations and increased recovery these fields will, however, remain on stream for many years to come. At Ekofisk, the operator hopes to continue production until 2050. These examples illustrate how considerable value can be created through increased recovery.

Extended lifetime

Figure 5.4 also shows that increased recovery extends a field's lifetime. This is positive, because it makes it possible to implement further development measures, and implies that the infrastructure will remain in place for a longer period, thus increasing the possibility of tie-ins of other discoveries to this infrastructure.

Figure 5.5 shows that a field's expected lifespan changes over time. This is because throughout the production period, increased insight and knowledge is gained by the operator which, in turn, provides the basis for implementing additional projects that were not profitable at the time of development. In addition, more efficient operation and the development and use of new technology have made it possible to implement projects that were formerly not profitable.

Increased recovery and extended lifetimes for fields provide greater value creation; however, in many cases they result in higher energy use. Measures designed to improve recovery often require significant amounts of energy and may entail additional emissions to air. When oil production declines, this can also lead to more production of the water that occurs naturally in the reservoir. These challenges are addressed in more detail in Chapter 9.

Efficient operations

The most important parameter for extending the lifetime of a field is economically profitable production. Efficient operations help reduce production costs. Therefore, efficient operations will affect resource recovery as profitable production can be maintained longer than if the operations were less efficient. This can help ensure that resources that are not currently profitable will still be produced. Many fields are facing a situation where the cost level must be reduced in order to justify profitable operations at a lower production level.

Developments in communications technology have given rise to new working methods. The introduction of integrated operations (IO) in the petroleum activity, entail that information technology is used to alter work processes to achieve better decisions, to remote-control equipment and processes, and to move functions and personnel onshore. The goal is reduced costs and more effective operations. In an international context, today's Norwegian petroleum industry has achieved great advances in the implementation of integrated operations. One of the reasons for this is that broadband (fibre-optic cable) has already been laid for transmission of large volumes of data to many of the fields. Integrated operations have already become an important element in many new developments and status reports from the operators indicate a committed effort towards integrated operations on many mature fields. Wherever profitable, existing fields will be linked to the digital infrastructure for implementation of the new technology.

New discoveries – effective use of infrastructure

In 2009, about NOK 136 billion was invested on the Norwegian continental shelf. Total investments on the Norwegian continental shelf have now reached about NOK 3000 billion in current monetary value. These investments have made it possible to establish extensive infrastructure which is a precondition for producing and marketing petroleum, but it also forms a basis for the development of additional resources in a cost-efficient manner.

As production from a field declines, spare capacity will often be available in the existing infrastructure. Such capacity may provide for an effective exploitation of resources that can be tied

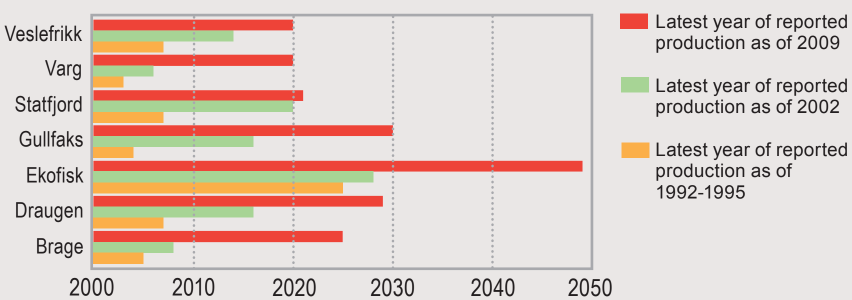


Figure 5.5 Lifetime for selected fields

(Source: Norwegian Petroleum Directorate)

in to existing infrastructure. In some cases, the use of existing infrastructure will be a prerequisite for profitable development of new fields, because some of these deposits are too small to justify their own separate infrastructure. Exploration for and development of resources near existing infrastructure can result in significant value for the Norwegian society.

Estimates from the Norwegian Petroleum Directorate indicate that approximately two-thirds of the undiscovered resources on the Norwegian continental shelf are likely to be located in the North Sea and the Norwegian Sea. These are the areas on the Norwegian continental shelf that currently have an extensive infrastructure. In order to map the prospects in these areas, and to be able to take advantage of the opportunities offered by the existing infrastructure, the authorities have established a proactive exploration policy for mature areas. Large areas are made available to oil companies in a predictable manner, while stringent requirements are set for those companies that are awarded exploration acreage. In extension of this policy, and on the basis of the fact that a number of fields are approaching decommissioning, it is important that the existing infrastructure is utilised efficiently, either by the owners themselves or by third-party users.

Large parts of the oil and gas activities on the Norwegian continental shelf have entered a more mature phase. In order to contribute to efficient use of existing infrastructure, such as existing platforms and pipelines, the Ministry of Petroleum and Energy issued new regulations on this topic in 2005, Regulations relating to use of facilities by others, which came into effect on 1 January 2006. The purpose of these regulations is to ensure efficient use of the infrastructure, and thus give the licensees sufficient incentives to carry out exploration and production activities. This objective shall be achieved by stipulating a framework for the negotiation process and for the establishment of tariffs and other conditions in agreements on third-party use of facilities. The regulations do not entail any change in the principle whereby it is the commercial players that are responsible for negotiating solutions acceptable to both parties.

Future trends

In order to ensure that the potential of producing fields and their surroundings is maximised, it is important that the participating interests are vested with the companies which want to make the most of them. This is why the authorities take a positive view of transfers of participating interests. In addition, the authorities have facilitated a broader range of players; reference is made to the discussion of new players in Chapter 4. The Norwegian authorities believe that a diversity of players, making different assessments and setting different priorities, constitutes a positive contribution towards realising the resource potential on the Norwegian continental shelf.

Increased recovery, extended lifetime and tie-in of resources in the vicinity of producing fields form the basis for creating substantial additional values for the society at large. However, increased recovery and longer lifetime are only relevant if this can be accomplished within prudent frameworks for the external environment, health, working environment and safety. In order to develop the resources in and around existing fields, the infrastructure already in place must often be utilised. This implies less freedom for companies compared to what is the case in new developments. For example, the selection of technical solutions must take into account the limitations associated with the equipment that is already in place, weight restrictions, etc.

In the medium term it is important to ensure that the decline in Norway's oil and gas production is minimised and that the fields' lifetimes are extended. On the basis of existing plans, we know that large volumes of oil and gas will be left behind when the fields are abandoned. Today, it is not profitable to recover these resources, but they represent a considerable potential that might be unlocked in the future. Realising this potential will require work on many fronts to explore all alternatives that can help in achieving this goal.

Figure 5.6 Optical fiber cables on the Norwegian continental shelf

(Source: Norwegian Petroleum Directorate)

6

NORWEGIAN GAS EXPORTS

Gas activities comprise an increasing part of the petroleum sector, and generate considerable revenues for the state. Norwegian gas is also important for the energy supply in Europe, and is exported to all of the major consumer countries in Western Europe. In terms of energy content, gas exports in 2009 were about eight times larger than the average Norwegian production of electricity. Norwegian gas exports supply approximately 15 per cent of the European gas consumption.[1] Most Norwegian exports go to Germany, the UK, Belgium and France, where Norwegian gas accounts for 25 to 35 per cent of the total consumption. Producers on the Norwegian continental shelf have entered into sales agreements with buyers in Germany, France, the UK, Belgium, the Netherlands, Italy, Spain, the Czech Republic, Austria and Denmark. From the Snøhvit field, Norway also supplies LNG (Liquefied Natural Gas) to the USA, Spain and other customers. Figure 6.2 shows historical and expected Norwegian gas sales. Sales of gas are expected to reach a level between 105 and 130 billions scm during the next decade.

The capacity in the Norwegian pipeline system is about 120 billion scm per year. There are four receiving terminals for Norwegian gas on the Continent: two in Germany, one in Belgium and one in France. There are also two terminals in the UK (see map). The Norwegian gas transport system consists of a network of more than 7800 km of pipelines. Treaties have been developed to govern rights and obligations between Norway and the countries that have landing sites for gas.

Achieving the highest possible value for Norwegian petroleum resources is a paramount goal. Most of the fields on the Norwegian continental shelf contain both oil and gas, and achieving the optimum balance between oil and gas production is vital. The gas management system must facilitate efficiency in all stages of the gas chain – exploration, development and transport.

All licensees on the Norwegian continental shelf are responsible for selling their own gas. Statoil sells the state's oil and gas, together with its own petroleum, in accordance with the regulations concerning marketing and sale of oil and gas.

One special feature of gas production is that it requires major investments in transport. Norwegian gas is mainly transported from the field to the consumer in pipelines. The authorities place great emphasis on evaluating a number of transport alternatives, so that the selected solution is as robust as possible. Costs involved in constructing pipelines are considerable, and there are significant economies of scale involved in investments in the transport system. In many cases, it may be appropriate to build the pipelines somewhat larger than initially needed, so that potential new gas discoveries can be transported through the existing pipeline system.

Sector organisation

The general policy instruments employed in gas resource management are exploration policy, conditions for approval of development plans and production licences for oil and gas (see Chapters 4 and 5). Many fields on the Norwegian continental shelf contain both gas and oil. When awarding gas production permits, the authorities take into account the prospects for optimum recovery of oil. On occasion, the authorities have awarded production permits for production of less gas than applied for by the companies, out of consideration for the need to produce oil. The authorities play an important part in establishing transport capacity and make sure that the processing- and transport capacity is in accord with different scenarios for new production in the medium to long term.

At the same time, it is important to ensure efficient operation, including achieving economies of scale. The Ministry of Petroleum and Energy

1 *OECD Europe.*

Figure 6.1 Gas pipelines

(Source: Norwegian Petroleum Directorate)

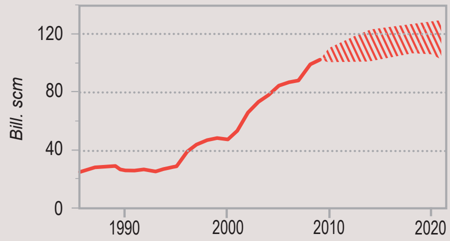


Figure 6.2 Sales gas from Norwegian fields

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

employs a number of instruments to achieve this. Three central instruments in the Norwegian gas transport system are: the operator Gassco AS, the joint ownership Gassled and regulated conditions for access to the transport system. The Ministry considers the use of these instruments in connection with development of new infrastructure and when the use of the existing infrastructure is changed. Operatorship, ownership and issues regarding regulated access can be employed independently.

Gassco

Gassco AS is the operating company for Gassled, which comprises most of the transport system on the Norwegian continental shelf. Gassco was established in 2001, and is wholly owned by the Norwegian state. Gassco is responsible for operations (planning, monitoring, coordination and administration of transport from the fields to the receiving terminals), allocation of capacity and development of the transport system.

Gassco shall contribute to comprehensive further development of the Norwegian gas infrastructure. In cases where major developments is considered, this means that all other Norwegian gas, not just the resources in fields that trigger a need for gas transport, must also be included in such evaluations. Further development of the gas infrastructure must take place in a manner that is expedient for the existing gas infrastructure on the Norwegian continental shelf.

A neutral company ensures that consideration is given to the submitted development alternatives for infrastructure, as well as exploitation of economics of scale. Gassco's task is to coordinate the processes for further development of the upstream network of gas pipelines, and to assess the need for such further development. Gassco recommends solutions, but does not itself invest in infrastructure. A neutral and independent operator of the gas transport system is important to ensure equal treatment of all users of the system, both as regards utilisation of the system and consideration of capacity increases. This is necessary to ensure efficient exploitation of the resources on the Norwegian continental shelf. Efficient exploitation of the existing gas transport system may also contribute to the reduction, or postponement, of the need for new investments.

Gassled

The transport system for Norwegian gas, i.e. the pipelines and terminals, is mainly owned by the Gassled partnership. Gassled encompasses all rich and dry gas facilities that are currently in use or are planned to be used to any significant degree, by parties other than the owners (third party use). New pipelines and transport-related facilities are intended to be included in Gassled from the time they are put to use by third parties, and are thus part of the central upstream gas transport system.

Common ownership of the transport system ensures that the gas is transported as efficiently as possible. The greatest value is created when avoiding conflicts of interest about which pipeline should be used to transport the gas.

Regulated access to the transport system

The pipeline system is a natural monopoly, requiring enormous initial investments. This is why gas transport tariffs are governed by special regulations issued by the Ministry of Petroleum and Energy. This ensures that the economic returns are earned from producing fields and not from the transport system. The oil companies' access to capacity in the system is based on their needs for gas transport. In order to secure good resource management, transport rights can be transferred between users when needs change. Gassco is responsible for allocating capacity.

Norwegian gas production 2009		
Pipeline exports	96 563 592 160	93.6 %
Sales to Norway	1 388 477 251	1.3 %
Sales to re-injection	1 840 204 978	1.8 %
LNG	3 367 516 686	3.3 %
Total	103 159 791 075	100.0 %

Source: Gassco/Norwegian Petroleum Directorate

Gassled – overall ownership structure for gas transport

The ownership split in Gassled as of 1.4.2010:

Petoro AS*	38,46 %
Statoil Petroleum AS	32,10 %
Total E&P Norge AS	7,78 %
Exxon Mobil Exploration and Production Norway AS	9,43 %
A/S Norske Shell	5,32 %
Norsea Gas AS	2,73 %
ConocoPhillips Skandinavia AS	2,00 %
Eni Norge AS	1,53 %
DONG E&P Norge AS	0,66 %

* Petoro AS is the licensee for the state's participating interest (State's Direct Financial Interest - SDFI).

Petoro's share in Gassled will be increased by approximately 8 per cent with effect from January 1st 2011, and the other licensees' shares will be adjusted correspondingly on the same date. The SDFI share in Norsea Gas AS is 40.0 per cent. When this is taken into account, the state, represented by SDFI, will have a share in Gassled of 39.4 per cent in 2003-2010 and 47.5 per cent from 2011. The licence period for most of the Gassled facilities will run until 31 December 2028.

The coordinated ownership structure for the most significant parts of the gas infrastructure has laid the foundation for a uniform access regime and will ease administration and daily operation of gas transport in the future. The ownership structure may be adjusted when new facilities and pipelines are incorporated into Gassled.

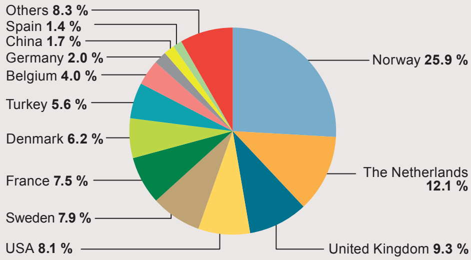


Figure 6.3 Sale of NGL/condensate 2009, about 22 mill. scm o.e, by country of first destination *(Source: Norwegian Petroleum Directorate)*

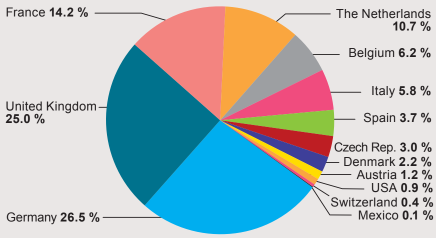


Figure 6.4 Norwegian natural gas exports 2009, about 100 bill. scm. by country *(Source: Norwegian Petroleum Directorate)*

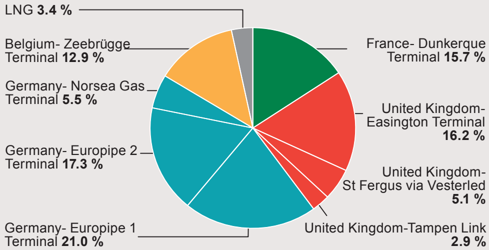


Figure 6.5 Norwegian natural gas exports, about 100 bill. scm by receiving terminal *(Source: Norwegian Petroleum Directorate/Gassco)*

7

DECOMMISSIONING

Figure 7.1 Installation 37/4-A, where the substructure is scheduled to be removed in summer 2010
(Source: ConocoPhillips Norge)

Petroleum activities only borrow the sea, and all phases of the oil and gas activities must respect the environment and other marine users. The main rule is that, when petroleum activity ceases, everything must be cleared and removed.

To date, the Ministry of Petroleum and Energy has approved more than ten decommissioning plans. In most cases it has been decided that abandoned facilities are to be removed and taken ashore, e.g. Odin, Nordøst Frigg, Øst Frigg, Lille-Frigg, Frøy and TOGI. Following consideration of the decommissioning plans for Ekofisk I and Frigg, permission was given to leave in place the concrete substructure and protective wall on the Ekofisk Tank, as well as the concrete substructure TCP2 at the Frigg field. The work to remove the facilities on the Frigg field and parts of Ekofisk commenced in 2005, and the facility 37/4-A is scheduled to be removed during summer 2010. The 37/4-A facility is located on the British side of the boundary line, but is included in the cessation plan for Ekofisk I.

The regulations

Both national and international regulations apply when the government reaches a decision regarding disposal of an installation on the Norwegian continental shelf. Disposal or decommissioning of facilities is regulated by the Petroleum Act of 1996. In addition to this Act, Norway's obligations under the OSPAR Convention (Convention for the Protection of the Marine Environment of the North-East Atlantic) also apply. OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations, which came into force on 9 February 1999, lays down guidelines for the various disposal alternatives that are acceptable for various types of marine installations. This decision does not cover pipelines, parts of an installation that are under the seabed and concrete anchor foundations that do not present an obstacle to fisheries.

The decision means that it is prohibited to dump or leave in place wholly or partially disused offshore installations in the marine environment. Derogation from the prohibition may be granted for individual installations, or parts of installations, if an overall assessment of the case in question shows that there are weighty reasons for disposal at sea.

If derogation from the OSPAR decision concerning disposal on land is applied for, a consultative process must be carried out in the OSPAR system. The appropriate authorities in the individual countries make the final decision and grant permission for exemption, if applicable. There are a number of conditions that must be met if permission is to be granted. Up until today, Norway has granted two exemptions from the OSPAR decision concerning disposal on land. As mentioned, permission has been granted to leave in place the concrete substructure of the Ekofisk Tank and its protective wall, as well as the concrete substructure TCP2 at the Frigg field.

The guidelines laid down in Storting White Paper No. 47 (1999–2000) *"Decommissioning of redundant pipelines and cables"* apply to pipelines and cables. As a general rule, pipelines and cables may be left in place when they do not obstruct or present a safety risk for bottom fishing, with costs of burial, covering or removal taken into consideration.

Decommissioning plans

As a main rule, the Petroleum Act requires licensees to submit a decommissioning plan to the Ministry of Petroleum and Energy two to five years prior to expiration or relinquishment of a production licence, or the use of a facility is terminated permanently.

The decommissioning plan must consist of two main parts, a disposal plan and an impact assessment. The impact assessment provides an overview of the expected consequences of the disposal, such as environmental consequences. The disposal plan is assessed by the Ministry of Petroleum and Energy and the Ministry of Labour (safety aspects). The Ministry of Petroleum and Energy coordinates the public hearing of the impact assessment.

The Ministry of Petroleum and Energy prepares a draft Royal Decree, which is submitted to the government, based on the impact assessment and feedback from the public hearing, as well as on the disposal plan and its assessment. Applications for derogation from the OSPAR decision concerning disposal on land must be presented to the Storting.

Liability

The licensees at the time of the Ministry's decision relating to disposal are under obligation to carry out the disposal. In 2009, the Petroleum Act was amended in such a way that the assignor of a participating interest in a license is alternatively liable for the financial obligations regarding disposal connected to the transferred participating interest.

Figure 7.2 Illustration of the Ekofisk Tank before and after removal of the topsides

(Source: ConocoPhillips)

If a decision entails abandonment, the legislation states that the licensees are liable for any damage or hindrance that may arise from the installation remaining in place, whether deliberate or negligent. However, the licensees and the state may agree that future maintenance and liability can be transferred to the state, in return for an agreed financial compensation.

8

RESEARCH, TECHNOLOGY AND INDUSTRIAL DEVELOPMENT

Norwegian petroleum industry

Building up Norwegian and Norwegian-based petroleum expertise has been an important element in Norwegian petroleum policy. In the beginning, much of this knowledge was obtained from foreign oil companies and supplier firms. Today, however, Norway has a highly developed and internationally competitive petroleum industry. This applies both to oil companies, the supplier industry and research institutions. The sector also provides valuable input to innovation and technological development in other sectors of Norwegian business and industry.

Supplier firms in Norway are represented in most steps of the value chain, from exploration and development to production and disposal. Norwegian suppliers are among the best in the world in fields such as seismic surveys, drilling equipment, subsea facilities and floating production solutions. These supplier firms are located in every county in Norway and the local and regional ripple effects of the petroleum activities are evident even in parts of the country that would not normally be expected to have a link to this industry. A study[1] conducted by Menon Business Economics shows that the industry generates more than tax revenues for the state. It creates jobs and stimulates local and regional business development. Increased internationalisation manifests itself as more local employment and value creation. Approximately 100,000 people are employed in the supplier industry in Norway.

Investments by oil companies in development, operation and maintenance on the Norwegian continental shelf generate a considerable demand

1 *KonKraft Report 4 Internationalisation*

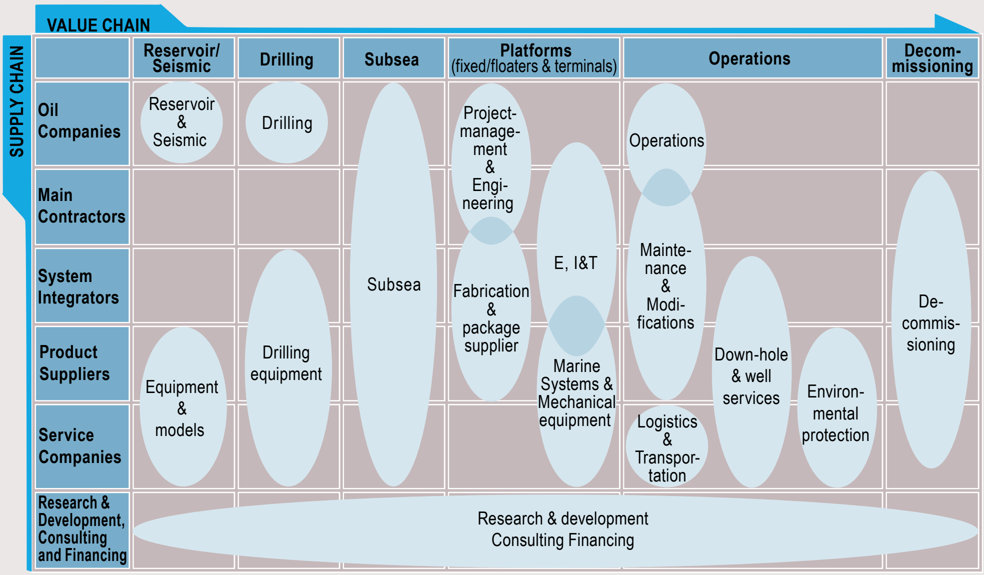


Figure 8.1 Map of the Norwegian Oil & Gas "World-Class" Clusters

(Source: www.Intsok.com)

for products and services from the supplier industry in Norway and abroad. Participation in international development projects is extremely important for the further development of the supplier industry. This international experience could also help reduce the cost level on the Norwegian continental shelf.

Research and technological development in the oil and gas sector

Development of new technology and increased competence in the oil and gas industry are important to ensure that the sector will continue to contribute to economic growth and general welfare in Norway. Technology and Research is also an important factor that contributes to more environmentally friendly oil and gas operations. Several of the solutions currently used by the oil and gas industry are the result of significant investments in research and technology development in the 1970s, 1980s and 1990s. In the years to come, however, value creation on the Norwegian continental shelf will be more technologically demanding and knowledge-intensive than is the case today. For this reason, continuing efforts in research and technology development are important to ensure a competitive Norwegian oil and gas industry. Figure 8.2 illustrates the organisation of petroleum research in Norway.

In order to meet the challenges associated with efficient and prudent petroleum activities, OG21 – oil and gas in the 21st century - was established on the initiative of the Ministry of Petroleum and Energy in 2001. OG21 is organised in a board, whose composition is determined by the Ministry of Petroleum and Energy, and a secretariat.

OG21 has managed to encourage oil companies, universities, research institutes, the supplier industry and the authorities to join forces and support a common national technology strategy for oil and gas.

The authorities' contribution to petroleum research is largely organised in the PETROMAKS and DEMO 2000 research programs. These programs are intended to contribute to attaining the goals identified in the OG21 strategy. The funds from the authorities are channelled through the Research Council of Norway, which coordinates the programs. Government sponsored petroleum research has an emphasis on environmental issues. The PETROMAKS Programme and the Demo 2000 Programme has therefore received financial support to follow up this priority.

PETROMAKS

PETROMAKS (maximum exploitation of the petroleum reserves) is a petroleum research program covering strategic fundamental research and development of expertise, user-related research

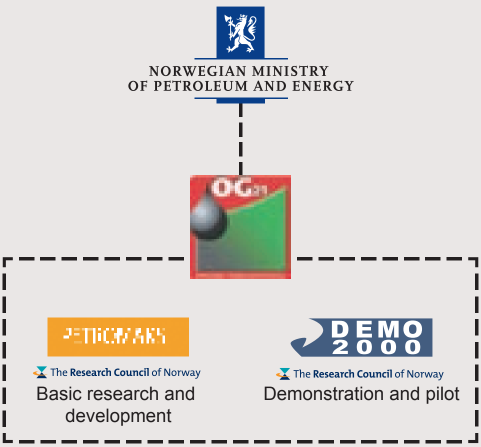


Figure 8.2 Ministry of Petroleum and Energy's involvement in petroleum research
(Source: Ministry of Petroleum and Energy)

and technology.. The program's target groups are Norwegian companies and research communities that wish to promote the build-up of knowledge and expertise in Norway. The national technology strategy, OG21, serves to guide PETROMAKS' priorities.

The objective of PETROMAKS is to contribute to better exploitation of fields in production and increased access to new reserves. The activities in the program are largely aimed at discovering more oil and gas, improving recovery from existing fields, streamlining transport of wellstreams over large distances and efficient transport of gas to the markets. The program also seeks to prepare a basis for development in HSE issues and the external environment, reducing the cost level on the Norwegian continental shelf and strengthening petroleum-related industrial development, in Norway and internationally. Another important objective of PETROMAKS is to contribute to an increased level of competence in the petroleum sector as well as to improve recruitment to the industry.

PETROMAKS also finances research on special arctic-related issues such as extreme climate, less developed infrastructure, development and production in ice-affected areas, handling of ice and transport over very long distances.

Other programs

DEMO 2000

An important initiative in the promotion of new technological solutions within the petroleum industry is the DEMO 2000 program. New technology is often associated with high costs and high risk, and it can be particularly challenging to get solutions out onto the market. The objective of DEMO 2000 is to contribute to reduced costs and risk for the industry and commercialisation of new technology by supporting pilot and demonstration projects. The program is based on the national technology strategy, OG21.

The pilot projects entail close cooperation with supplier firms, research institutions and oil companies; a collaboration which, in itself, helps to develop a progressive, market-oriented expertise network.

The DEMO 2000 program has supported demonstration of new petroleum technology since

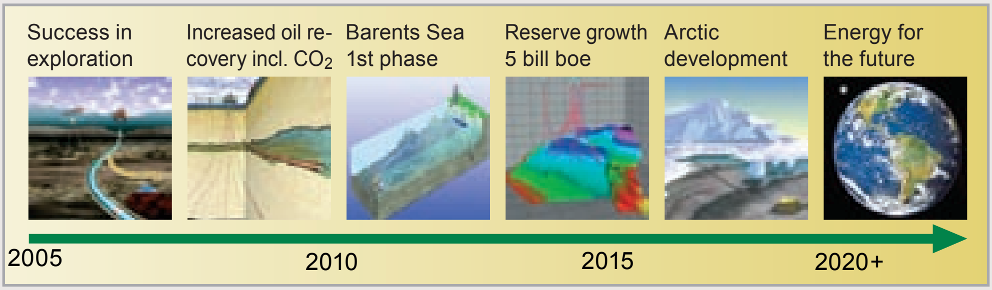


Figure 8.3 OG21's technology road map for value creation on the Norwegian continental shelf *(Source: OG21)*

1999. Some of the technologies developed through the program are already available on a commercial basis, and have resulted in significant cost savings for the industry. DEMO 2000 believes there is a great potential within technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling and integrated operations (remote control). Innovations within these areas carry a substantial potential for increased value creation.

The DEMO 2000 program, like PETROMAKS, emphasises developing and testing petroleum technology with particular relevance for arctic conditions.

PETROSAM

PETROSAM is a social-scientific petroleum research program. The aim of the program is to provide insight and competence regarding social conditions relevant to strategic and policy-making decisions of the government and the petroleum sector. PETROSAM will also focus on international relations, in particular the Middle East and Russia. PETROSAM was established in 2006 and will continue until 2012.

PROOF

The research program PROOF examines long-term effects of discharges to sea from petroleum activities, and constitutes a part of the larger program, "The Sea and the Coast", which is planned for the period 2006–2015.

9

ENVIRONMENTAL CONSIDERATIONS IN THE NORWEGIAN PETROLEUM SECTOR

Introduction

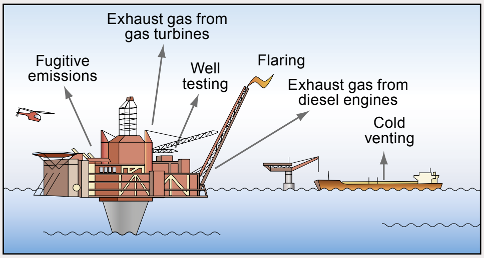
Consideration for the environment has always been an integrated part of the Norwegian petroleum activities. A comprehensive set of policy instruments has been developed to safeguard consideration for the natural environment in all phases of the activities, from licensing rounds to exploration, development, operations and decommissioning. The strict regulation of flaring through the Petroleum Act contributes to a low general level of flaring on the Norwegian continental shelf, compared with other countries.

Norway was one of the first countries to introduce a substantial CO_2 tax in 1991. This tax has led to development of technology and triggered initiatives that led to considerable emission reductions. The authorities and the petroleum industry have worked together closely to reach the objective of zero environmentally hazardous discharges to sea from the petroleum activities (zero discharge target). As a result, the zero discharge targets are considered to be achieved as regards discharges of chemical additives. As a result of the continuous strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental standards compared with petroleum sectors in other countries.

This chapter provides an overview of emissions and discharges from the petroleum activities, as well as policy instruments and measures designed to ensure consideration for the environment.

Emissions from the petroleum activities

Emissions to air from the petroleum sector largely consist of exhaust gases from combustion of gas in turbines, flaring of gas and combustion of diesel. These exhaust gases contain components such as CO_2 and NO_x. Other emissions released include nmVOC, methane (CH4) and sulphur dioxide (SO2). Discharges from the petroleum sector to sea contain residues of oil and chemicals used



Overview of emission/discharge sources

in the production processes, as well as naturally occurring chemical substances.

Acts and legislation that regulate emissions and discharges from the sector

Emissions and discharges from petroleum activities in Norway are largely regulated by the Petroleum Act, the CO_2 Tax Act, the Special Tax Act, the Greenhouse Gas Emission Trading Act and the Pollution Control Act. Petroleum facilities on land are subject to the same types of policy instruments as other land-based industry. The processes involved in evaluating consequences and approving new development plans (PDOs/PIOs) are key elements of the petroleum legislation. Facilities located on land or at sea within the baseline are also subject to the scope and extent of the Planning and Building Act (see Chapter 5).

In addition to the aforementioned statutes, Norway has committed to reducing some of the emissions and discharges under various agreements.

Measuring and reporting discharges and emissions

The Norwegian Climate and Pollution Agency (CPA), the Norwegian Petroleum Directorate (NPD) and the Norwegian Oil Industry Association have established a joint database, Environmental Web (EW), to report discharges to sea and emissions to air from the petroleum activities. Since

2004, all operators on the Norwegian continental shelf report emission/discharge data directly in this database. This allows both the operating companies themselves and the authorities to more easily analyse historical emissions to air and discharges to sea in a more complete and consistent manner.

Emissions to air

The agreements regarding emissions to air usually specify emission limits for each country. The wording of the agreement determines whether the imposed limits must be implemented completely within the borders of each country, or whether reductions can also be implemented in other countries where the costs of such reductions may be lower. The costs associated with reducing emissions from the various sources, both national and international, have an impact on the types of measures implemented vis-à-vis the petroleum sector.

After the Kyoto Protocol, Norway has an emissions target which entails that the country's average greenhouse gas emissions for the years 2008–2012 shall not increase more than one per cent compared with the emission level in 1990. Compared with today's level, this would mean a reduction of greenhouse gas emissions by about 7 per cent. The requirement will be met by reducing emissions both nationally and in other countries using the Kyoto mechanisms ”Clean Development Mechanism (CDM)” and ”Joint Implementation (JI)”.

The Climate White Paper presented in June 2007, entails that Norway should exceed the Kyoto target by 10 percentage points. The climate compromise of January 2008 suggested that Norway would become carbon-neutral in 2030.

With the Greenhouse Gas Emission Trading Act, Norway established a national quota system for greenhouse gases starting in 2005 as a follow-up of the Kyoto Protocol. The Greenhouse Gas Emission Trading Act was revised in 2007 and in February 2009. Norway implemented the EU's directive on emission trading in the fall of 2007, and the Norwegian quota system is linked to the EU's quota system for the period 2008–2012. In December 2008, the EU agreed on an emissions trading directive for the period 2013–2020. This directive is now being considered by the EEA/EFTA countries.

Emissions that have regional environmental consequences are regulated in the protocols under the Convention on Long-Range Transboundary Air Pollution (the LRTAP Convention). Together with the USA, Canada and other European countries, Norway signed the Gothenburg Protocol in 1999. This protocol seeks to solve the environmental issues of acidification, over-fertilization and ground-level ozone. The Gothenburg Protocol took effect on 17 May 2005. Under this Protocol, Norway is to reduce NO_x emissions to 156,000 tonnes by 2010. This means a 29 per cent reduction compared with the 1990 emission levels. As regards nmVOC, the commitment is approximately the same as Norway assumed under the prevailing Geneva Protocol, which requires annual nmVOC emissions from the entire mainland and the Norwegian economic zone south of the 62nd parallel to be reduced as soon as possible by 30 per cent compared with the 1989 level. Under the Gothenburg Protocol, total national emissions shall not exceed 195,000 tonnes per year by 2010. Due to the combination of reduction measures implemented on the shuttle tankers loading on the Norwegian continental shelf and reduced oil production, these requirements are met.

The EU directive on National Emission Ceilings for certain atmospheric pollutants (the NEC Directive) was implemented in the EEA-agreement in the autumn of 2009. The directive sets upper limits for each Member State for the total emissions in 2010 of the same four pollutants that are regulated by the Gothenburg Protocol. The Norwegian ceilings will be similar to those defined in the Gothenburg Protocol.

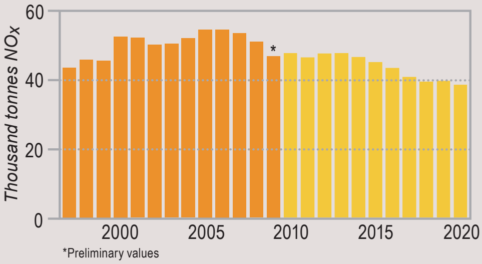


Figure 9.7 Emissions of NO_x from the petroleum activities
(Source: Norwegian Petroleum Directorate)

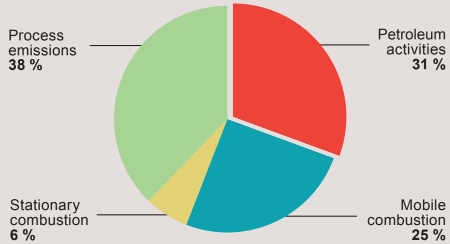


Figure 9.8 Sources of Norwegian emissions of nmVOC, 2008
(Source: Statistics Norway)

exemption for emission sources which were part of environmental agreements with the State on introduction of measures to reduce NO_x in accordance with stipulated environmental targets. The Norwegian State (represented by the Ministry of the Environment) and the industry organisations have entered into an environmental agreement on reduction of NO_x.

The industry organisations have established a dedicated NO_x fund that will be used to fulfill the commitments under this agreement. On behalf of the industry organisations, the fund collects payments per kilogram of NO_x emissions from enterprises that have endorsed the agreement. The fund also provides subsidies for cost-effective measures aimed at reducing NO_x emissions. As of 15 February 2010 more than 580 businesses had joined the environmental agreement according to the NHO (Confederation of Norwegian Enterprise). Most petroleum industries have now joined the agreement.

Examples of measures for reducing NO_x emissions

Low-NO_x burners

Low-NO_x burners are one such measure. These burners can be retrofitted on existing turbines. Studies show that the general cost level associated with retrofitting such burners is considerably higher than previously assumed. Generally speaking, low-NO_x technology installed on machinery running at high efficiency will result in significantreduction in NO_x emissions. On machinery running at low capacity, CO_2 emissions increase, while NO_x reductions are less when the utilization of capacity is high.

Emission status for nmVOC

nmVOC stands for non-methane volatile organic compounds, which are vapours from substances such as crude oil.The environmental effects of nmVOC include formation of ground-level ozone, which can damage health, crops and buildings. Direct exposure to nmVOC can cause respiratory tract damage and nmVOC contributes indirectly to the greenhouse effect in that CO_2 and ozone are formed when nmVOC reacts with air in the atmosphere.

The petroleum sector has been the main source of nmVOC emissions in Norway (see Figure 9.8), Emissions of nmVOC from the petroleum sector largely originate from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals. Other industrial processes and road traffic are also important sources of nmVOC emissions in Norway. The petroleum sector's share of this is shrinking due to the phase-in of emission-reducing technology. Emissions of nmVOC per produced unit of oil have also declined significantly in recent years (see Figure 9.9).

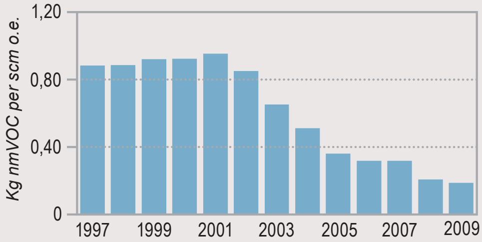


Figure 9.9 Sources of nmVOC emissions per produced unit
(Source: Norwegian Petroleum Directorate)

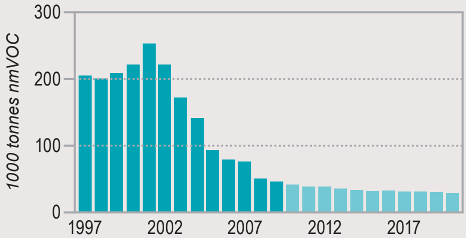


Figure 9.10 Emissions of nmVOC from the petroleum activities
(Source: Norwegian Petroleum Directorate)

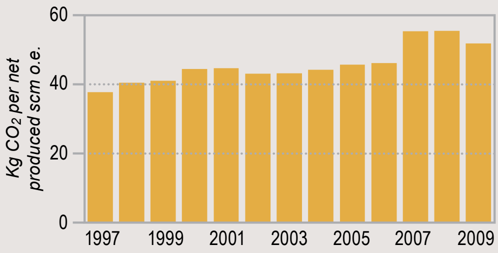


Figure 9.3 Emissions of taxable CO_2 per produced unit
(Source: Norwegian Petroleum Directorate)

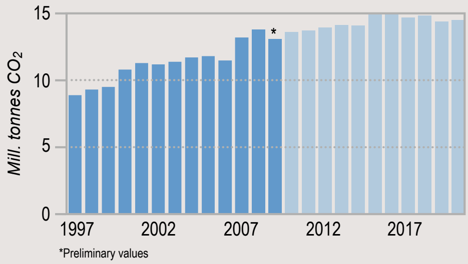


Figure 9.4 Emissions of CO_2 from the Norwegian petroleum sector
(Source: Norwegian Petroleum Directorate)

All plans for development and operation of oil and gas fields (PDOs/PIOs) must contain an analysis of potential power supply from land. This applies both to new field developments and major modifications to existing installations.

Examples of measures aimed at reducing CO_2 emissions

In addition to the overarching policy instruments, there are also concrete, practical measures on the shelf. The authorities and the oil companies have a strong commitment to research and development of technology to find good technical solutions that can contribute to reducing emissions which can harm the environment. Much is being done to develop environmental competence and environmental technology, and the Norwegian oil industry is a frontrunner when it comes to applying environmentally friendly solutions. This has yielded results, and many of the solutions first applied in Norway have become export commodities.

Combined power

Combined power is a solution which utilises heat from the exhaust gas in the turbines to produce steam, which is in turn used to generate electricity. Combined power boosts energy efficiency, and it is currently in use on the Oseberg, Snorre and Eldfisk fields. These facilities are unique in a global offshore context.

Storage of CO_2

CO_2 can be injected and stored in depleted oil and gas reservoirs, or in geological formations under the sea bed or onshore. Since 1996, approximately one million tonnes of CO_2 have been stored annually in the Utsira formation in connection with processing of gas from the Sleipner field. Storing CO_2 in the Utsira formation is unique. This is the only facility in the world where large quantities of CO_2 are stored in a geological formation under the seabed. On the Snøhvit field, starting in April 2008, CO_2 from the gas stream is separated and stored before the natural gas is cooled to liquid natural gas (LNG). The CO_2 gas is transported via pipeline from the LNG plant on Melkøya and back to the field for reinjection and storage in the Tubåen formation, 2600 metres below the seabed. When the Snøhvit field is operating at full capacity, up to 700,000 tonnes of CO_2 may be stored each year.

Energy management and energy efficiency

Many energy efficiency measures have been implemented after the CO_2 tax was introduced in 1991. A fundamental shift in technology and energy supply concepts is needed to ensure even better energy efficiency over the long term. This demands a long-term commitment to development, testing and implementation of new technology.

Electrification must be viewed in light of the fact that there are considerable variations between the facilities as regards technical properties, costs, power capacity and, not least, the effect on other power consumers through connection to the general power supply. One also has to take into account that both onshore and offshore emissions are subject to CO_2 quota obligations.

In January 2008, the Norwegian Petroleum Directorate (NPD), the Norwegian Water Resources and Energy Directorate (NVE), the Norwegian Climate and Pollution Agency (CPA) and the Petroleum Safety Authority Norway (PSA) submitted a report to the government. The report was a new review of the costs associated with supplying the petroleum activities on the shelf with power from land.The new calculations show that the costs of measures needed to electrify an area with existing facilities was in the range of NOK 1600 to 5000 per tonne of CO_2. The report also showed that nearly 45 per cent of the emissions from the sector cannot be replaced by electricity from land (such as emis-

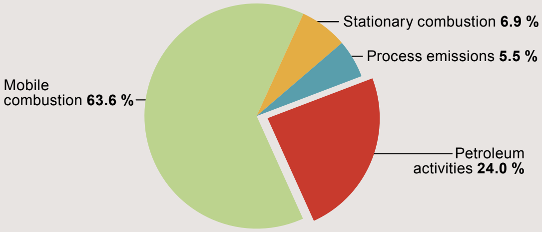


Figure 9.5 Sources of NO_x emissions in Norway, 2008
(Source: Statistics Norway)

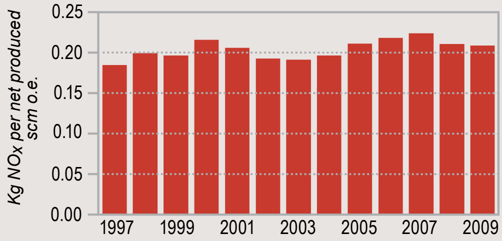


Figure 9.6 NO_x emissions per produced unit
(Source: Norwegian Petroleum Directorate)

sions from floating facilities and emissions linked to gas flaring as a safety measure).

As of today, several fields already receive all or parts of their power supply from land. For example, the Troll A and Ormen Lange facilities use power from the grid, while Valhall Redevelopment, Goliat and the Gjøa field will be developed using power from land. Approximately 43 percent of Norwegian gas production comes from fields which have power from shore.

Emission status for NO_x

Emissions of CO_2 and NO_x are closely connected. As for CO_2, gas combustion in turbines, flaring of gas and diesel consumption on the facilities are key emission sources also for NO_x. The volume of emissions depends both on the combustion technology and the quantity of fuel used. For example, combustion in gas turbines yields lower emissions of NO_x than combustion in diesel motors. NO_x are a mixture of nitrogen compounds which contributes to acidification. The environmental effects of NO_x emissions include impact on fish and other fauna through acidification of watercourses and the ground damage to health, crops and buildings due to production of ground-level ozone.

Mobile sources account for the majority of the Norwegian NO_x emissions (see Figure 9.5). The petroleum sector contributes 24 per cent. Emissions of NO_x per produced oil equivalent have risen slightly since 1997 (see Figure 9.6). Total emissions of NO_x from the sector have also increased from 1991 (see Figure 9.7). The main cause of the growth to date is increased activity, which has entailed a need for more energy, and in turn, more emissions.

Measures for reducing NO_x emissions

PDOs/PIOs

In the operations phase, emissions of scm on the continental shelf are regulated by conditions that may be set in connection with consideration of the PDO/PIO. Emission permits may also be issued pursuant to the Pollution Act, which includes NO_x.

> ## Klimakur 2020
> In February 2010, by mandate from the government, an expert group named Klimakur 2020 delivered a report on measures and instruments that can help reach the national target for greenhouse gas emissions in 2020.
>
> The group has investigated measures and instruments applicable to the sectors of transport, industry, building and district heating, agriculture, forestry, waste, and petroleum. In the petroleum sector, the measures have a cost range from 400 to 4 000 kroner per ton CO_2 reduced. There are significant uncertainties related to these estimates. Some of the measures are large and complicated industrial projects that will take time to realise. The report estimates that the reduction potential in the petroleum sector could amount to 3 million tons of CO_2 by 2020.
>
> The total estimated technical potential for emission reductions, all sectors included, is approximately 22 million tons of CO_2.
>
> The Klimakur report was sent on public hearing during spring 2010. For more information on Klimakur 2020, go to www.klimakur.no

NO_x tax and the Gothenburg Protocol

On 28 November 2006, the Storting adopted a tax on emissions of NO_x. The legal basis for this is found in the amendment (1 January 2007) of the Regulations relating to special tax. The tax applies to all emissions from the petroleum activities from turbines with a gross added energy greater than 10 MW and machinery larger than 750 hp, as well as emissions from flaring. In 2010 the tax is set at NOK 16,4 per kg of NO_x.

The tax largely targets emissions from domestic activities, and includes emissions from major within the maritime and aviation sectors, land-based activities, as well as on the continental shelf.

In connection with the Storting's consideration of the NO_x tax, a decision was made to grant an

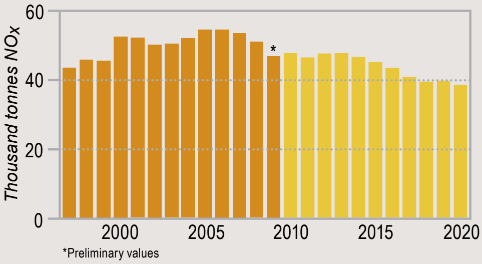


Figure 9.7 Emissions of NO_x from the petroleum activities
(Source: Norwegian Petroleum Directorate)

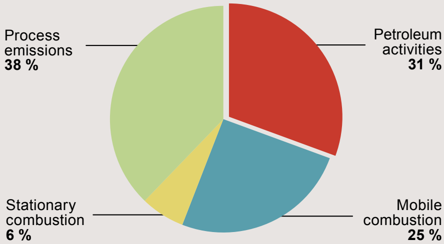


Figure 9.8 Sources of Norwegian emissions of nmVOC, 2008
(Source: Statistics Norway)

exemption for emission sources which were part of environmental agreements with the State on introduction of measures to reduce NO_x in accordance with stipulated environmental targets. The Norwegian State (represented by the Ministry of the Environment) and the industry organisations have entered into an environmental agreement on reduction of NO_x.

The industry organisations have established a dedicated NO_x fund that will be used to fulfill the commitments under this agreement. On behalf of the industry organisations, the fund collects payments per kilogram of NO_x emissions from enterprises that have endorsed the agreement. The fund also provides subsidies for cost-effective measures aimed at reducing NO_x emissions. As of 15 February 2010 more than 580 businesses had joined the environmental agreement according to the NHO (Confederation of Norwegian Enterprise). Most petroleum industries have now joined the agreement.

Examples of measures for reducing NO_x emissions

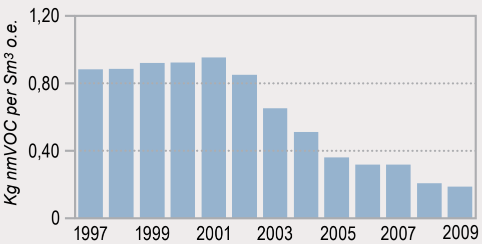
Low-NO_x burners

Low-NO_x burners are one such measure. These burners can be retrofitted on existing turbines. Studies show that the general cost level associated with retrofitting such burners is considerably higher than previously assumed. Generally speaking, low-NO_x technology installed on machinery running at high efficiency will result in significantreduction in NO_x emissions. On machinery running at low capacity, CO_2 emissions increase, while NO_x reductions are less when the utilization of capacity is high.

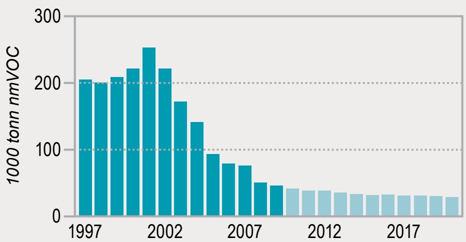
Emission status for nmVOC

nmVOC stands for non-methane volatile organic compounds, which are vapours from substances such as crude oil.The environmental effects of nmVOC include formation of ground-level ozone, which can damage health, crops and buildings. Direct exposure to nmVOC can cause respiratory tract damage and nmVOC contributes indirectly to the greenhouse effect in that CO_2 and ozone are formed when nmVOC reacts with air in the atmosphere.

The petroleum sector has been the main source of nmVOC emissions in Norway (see Figure 9.8), Emissions of nmVOC from the petroleum sector largely originate from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals. Other industrial processes and road traffic are also important sources of nmVOC emissions in Norway. The petroleum sector's share of this is shrinking due to the phase-in of emission-reducing technology. Emissions of nmVOC per produced unit of oil have also declined significantly in recent years (see Figure 9.9).



Figur 9.9 nmVOC-utslepp per produsert eining
(Kjelde: Oljedirektoratet)



Figur 9.10 Utslepp av nmVOC frå petroleumsverksemda
(Kjelde: Oljedirektoratet)

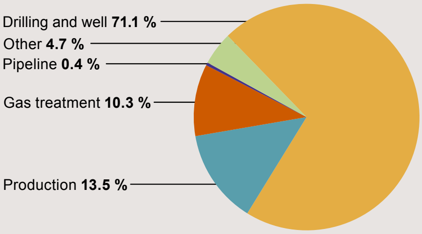


Figure 9.11 Discharges of chemicals from Norwegian petroleum activities, by sources, 2009
(Source: Norwegian Petroleum Directorate)

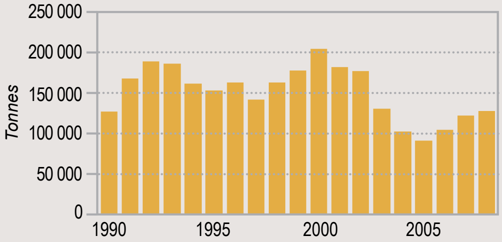


Figure 9.12 Total discharges of chemicals from Norwegian petroleum activities
(Source: Norwegian Petroleum Directorate)

Total emissions of NMVOC were161 000 tons in 2009. This is 6 percent less than the year before and below the requirements of the Gothenburg protocol for 2010 (195 000 tons). From 1990, emissions have decreased by 43 percent and from the peak year of 2001 by a total of 57 percent.

85 percent of the decline from 2007 to 2008 is due to lower emissions from loading and storage of oil on the continental shelf. The national reductions from 2001 are also mainly caused by the decrease in these emissions.

The forecast for emissions of nmVOC from the sector shows a distinct declining trend in the years to come (see Figure 9.10). Implementation of emission-reducing technology is the main reason for this.

Measures and instruments for reducing nmVOC emissions

For a number of years, the oil companies have worked to make technology for recovering nmVOC available to storage vessels and shuttle tankers. Today, tested technology exists that can reduce emissions from loading by approximately 70 per cent. The joint venture agreement on industry collaboration was signed in 2002. The agreement helps coordinate phase-in of technology and to fulfil the requirement in an expedient and cost-effective manner.

A recovery facility for nmVOC was deployed at the crude oil terminal at Sture in 1996. This facility is the first of its kind in a crude oil terminal. In order for loading tankers to use the facility, they must be fitted with coupling equipment. From 1 January 2003, it became a requirement that all vessels must be fitted with equipment for recovering nmVOC. Ships without the necessary equipment are not normally granted access to the facility.

Discharges to sea

Discharges to sea mainly include produced water, drill cuttings and residues of chemicals and cement from drilling operations. Discharges of oil and chemicals can have local effects in the area near the facilities, and such discharges are regulated at the national level through discharge permits based on the Pollution Act. These discharges are also subject to international regulation through the Oslo-Paris Convention on discharges to sea (the OSPAR Convention). For discharges to sea, the stipulated international maximum level for oil content in water was reduced to 30 mg per litre starting from 2007. Use and discharge of chemicals are regulated at the international level in the form of risk assessment requirements and categorisation according to the properties of the chemicals.

The objective of zero hazardous discharges to sea from the petroleum activities was established

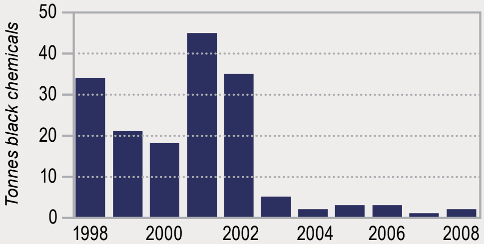


Figure 9.13 Discharges of black chemicals from petroleum activities
(Source: Norwegian Petroleum Directorate)

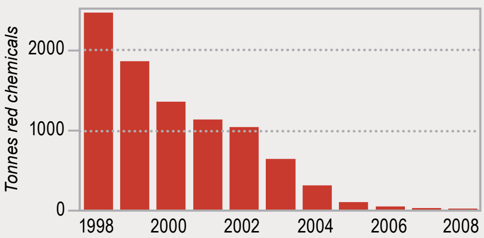


Figure 9.14 Discharges of red chemicals from the petroleum activities
(Source: Norwegian Petroleum Directorate)

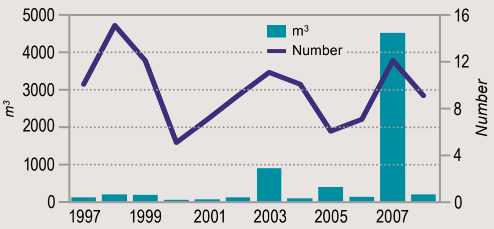


Figure 9.15 Acute oil discharges of more than one cubic metre *(Source: Norwegian Petroleum Directorate)*

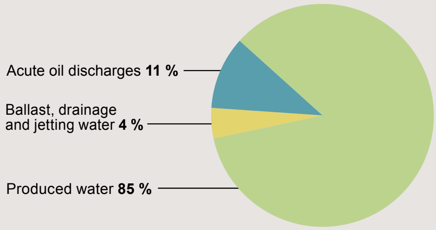


Figure 9.16 Discharges of oil from the petroleum activities, by activity, 2009 *(Source: Norwegian Petroleum Directorate)*

in 1997. The main rule is that no environmentally hazardous substances may be discharged, neither chemical additives nor chemical substances that naturally occur in the environment. After the objective of zero discharges to sea was confirmed, the authorities and the industry have worked together to find solutions aimed at achieving this goal.

The oil industry has invested billions in reducing discharges to sea, and the implemented measures have significantly reduced these discharges. Discharges of environmentally hazardous chemical additives (red and black categories) have for instance been reduced by more than 99 per cent since 1997 and the zero discharge target is considered to be achieved as regards chemical additives.

Discharge status for chemicals

Chemicals are a generic designation for all additives and auxiliary products used in drilling and well operations and in the production of oil and gas. The main rule is that no environmentally hazardous substances may be discharged, regardless of whether the substance is an additive or occurs naturally.

The contribution from the petroleum sector to national discharges to sea is less than 3 percent of the environmental toxins on the Norwegian Climate and Pollution Agency's list.

More than 99 per cent of the chemicals used in the Norwegian petroleum activities consist of chemicals which are believed to have little or no impact on the environment (green and yellow chemicals). Many of these chemicals are substances that occur naturally in seawater. The remainder are environmentally hazardous chemicals or chemicals whose potential effects have not been adequately documented.

Some of the environmental effects caused by chemicals include that they have a certain local toxic effect, but are diluted in the water column so that the acute impact on the environment is not very significant other than in the immediate vicinity of the discharge. A small percentage of chemical discharges may have very serious environmental consequences.

Most chemical discharges are associated with drilling activity (see Figure 9.11), and discharge volumes vary according to the level of activity taking place. Figure 9.12 shows the development in total discharges of chemicals from the petroleum activities. Discharges of added environmentally hazardous production chemicals (black and red chemicals, ref. CPA's classification) have been reduced by 94 per cent for black chemicals and 98 per cent for red chemicals since 2000. Figures 9.13 and 9.14 illustrate the development in discharges of environmentally hazardous chemicals.

The chemicals that are not discharged are dissolved in the oil, deposited in the subsurface or are handled as hazardous waste.

Measures for reducing discharge of chemicals

Companies must apply for discharge permits from the CPA in order to discharge chemicals to the sea. The CPA issues discharge permits pursuant to the rules of the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary emergency preparedness to deal with acute pollution, in addition to municipal and national emergency preparedness.

Discharges of oil

Total discharges of oil from the Norwegian petroleum activities account for a small portion of the total discharges into the North Sea. The majority of oil discharged into the North Sea comes from shipping and from the mainland via rivers. Estimates indicate that about 5 % of total oil discharges in the North Sea come from the petroleum industry.

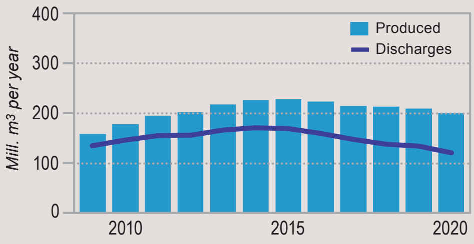


Figure 9.17 Forecast for produced water and discharges of produced water *(Source: Norwegian Petroleum Directorate)*

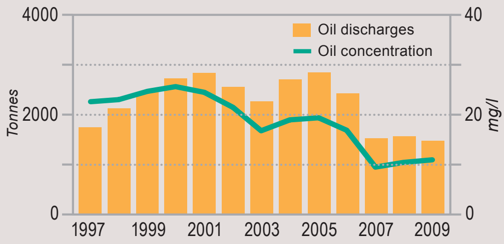


Figure 9.18 Discharge of oil in produced water and corresponding oil concentration *(Source: Norwegian Petroleum Directorate)*

Acute discharges of oil

Figure 9.15 provides an overview of acute oil discharges greater than one cubic meter (m^3). All acute discharges from the facilities on the Norwegian continental shelf are reported to the National Coastal Administration, and the causes of the discharges are investigated. The petroleum sector has not caused major acute oil spills that have led to damage to the environment. In 2009, the total volume of acute discharges to sea was 104 m^3 (see Figure 9.15). The total acute discharges to sea in 2007 were 4408 m^3, as a result of the incident at Statfjord.

The environmental effects of potential acute oil spills depend on several factors, and not only the size of the spill. The location of the spill, season, wind strength, currents and the effectiveness of the response measures are all crucial for the extent of damage. Acute oil spills can harm fish, marine mammals, seabirds and beach zones. Most serious acute oil spills in Norway have originated from ship traffic near the coast.

Water that is produced with oil and gas contains remnants of oil in the form of droplets (dispersed oil) and other organic components (including dissolved oil fractions). The produced water is re-injected into the subsurface or cleaned before it is discharged to sea. Oily cuttings and drilling fluid that previously accounted for a large share of the oil discharged from the petroleum activity, are now re-injected into suitable reservoirs or taken to land for further treatment. Figure 9.16 shows oil discharges distributed by activities, while Figure 9.17 illustrates the predicted development in the volume of produced water and discharges of produced water. Implemented measures have led to considerable reductions in the discharge of oil per unit of produced water.

Measures for reducing discharges of oil

The companies must apply for discharge permits in order to discharge oil to the sea, following the same procedure as for chemicals. The CPA grants discharge permits pursuant to the rules in the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary emergency preparedness to deal with acute pollution, in addition to municipal and national emergency preparedness.

Oil spill preparedness

In Norway, the preparedness for acute pollution consists of private sector preparedness, municipal preparedness and state preparedness. The Ministry of Fisheries and Coastal Affairs and the Norwegian Coastal Administration are responsible for coordinating the total national oil spill preparedness, as well as the government's preparedness for acute pollution. The Ministry of the Environment is responsible for setting preparedness requirements for acute pollution in municipalities and for private enterprises. The CPA approves the emergency preparedness plans and ensures that the demands are complied with.

On behalf of the oil companies, the operators are responsible for handling acute incidents that are a result of their own activities, using preparedness resources that are designed for this purpose. The Norwegian Clean Seas Association for Operating Companies (NOFO), which consists of a number of companies that are licensees on the Norwegian continental shelf, has also established regional plans which take into consideration reinforcement of ocean-going preparedness, coastal preparedness and beach zone preparedness. NOFO manages and maintains preparedness which includes personnel, equipment and vessels. NOFO has five bases along the coast – Stavanger, Mongstad, Kristiansund, Træna and Hammerfest, in addition to some fields where NOFO equipment is permanently located. NOFO has a total of 16 oil spill preparedness systems and carries out training exercises each year.

Definitions

Environmentally hazardous compounds, environmentally hazardous chemical substances, environmentally hazardous components:
Substances or groups of substances with properties including toxicity, low biodegradation, potential bioaccumulation and/or hormone disruption. The most dangerous of these substances are classified as environmental toxins.

Environmentally harmful discharges: This term refers to the damage that emissions and discharges can cause, and depends on the quantity released, the location and time of the release. An environmentally harmful discharge may be of an environmentally hazardous substance, but it may also be a substance that has no such inherent characteristics.

Zero discharge targets for environmentally hazardous substances:
Zero discharges, or minimisation of discharges of naturally occurring environmental toxins encompassed by the end objective for chemicals hazardous to health and the environment, ref. the priorities list in Storting White Paper No. 25 (2002–2003).

Zero discharges of chemical additives in the Norwegian Pollution Control Authority's black category (general prohibition on use and discharge) and the red category (high priority for phasing out via substitution).

Other chemical substances:
Zero discharges or minimisation of discharges that can lead to harm to the environment, including oil (components that are not hazardous to the environment), substances in the CPA's yellow and green categories, cuttings and other substances that can lead to harm to the environment *

Source: Storting White Paper No. 25 (2002–2003) The Environmental Policy of the Government and the State of the Environment in Norway.

Storting White Paper No. 38 (2003–2004) *On the petroleum activities*, stipulated specific conditions for petroleum activities in the Lofoten–Barents Sea area. The Lofoten–Barents Sea area is defined as a particularly vulnerable area, which is subject to more stringent discharge requirements than those in place for the rest of the Norwegian continental shelf.

No discharge of produced water. Injection of produced water is the assumed basis, or use of other technology that prevents discharge of produced water. In case of operational deviation, maximum 5 per cent of the produced water can be released to sea if it is cleaned (before discharge to sea).

No discharge of drill cuttings or drilling fluids. Drill cuttings and drilling fluids will be reinjected or taken to land for disposal. Drill cuttings from the top hole section may normally be discharged under the condition that the discharge does not contain substances with unacceptable environmental effects, and only in areas where the potential for damage to vulnerable environmental components is considered to be low.

No discharge to sea from well testing.

** Ref. Regulations relating to conduct of activities in the petroleum activities (the Activities Regulations) of 3 September 2001.*

10

PETROLEUM RESOURCES

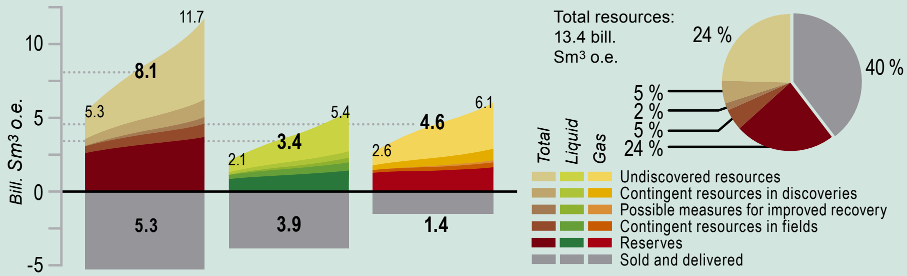


Figure 10.1 Petroleum resources and uncertainty in the estimates per 31.12.2009
(Source: Norwegian Petroleum Directorate)

The Norwegian Petroleum Directorate (NPD) estimates that the total discovered and undiscovered petroleum resources on the Norwegian continental shelf amount to approximately 13 billion standard cubic metres of oil equivalents (scm o.e.). Forty per cent of the total resources, 5.3 billion scm o.e., have been produced. The total remaining recoverable resources amount to 8.1 billion scm o.e. Of this volume, 4.8 billion scm o.e. are proven resources, while the estimate for undiscovered resources is 3.3 billion scm o.e.

The total growth of recoverable resources from exploration activity in 2009 is 62 million scm oil and 83 billion scm gas. 28 new discoveries were made from a total of 72 completed exploration wells. Several of these discoveries are still being evaluated, so the estimates are very uncertain.

Since production started on the Norwegian continental shelf in 1971, petroleum has been produced from a total of 78 fields. In 2009, five new fields, Alve, Rev, Tyrihans, Volund and Yttergryta came on stream. At the end of 2009, 52 of the producing fields are located in the North Sea, 12 in the Norwegian Sea and one in the Barents Sea. The PDOs for two new fields, Goliat and Oselvar, were approved in 2009. PDO exemptions were granted for Vega Sør oil and Snorre Export.

Figure 10.1 shows the estimates for recoverable resources on the Norwegian continental shelf. The volumes are divided according to the NPD's resource classification, and show total resources, liquid and gas.

Resources

"Resources" is a collective term for technically recoverable quantities of petroleum. Resources are classified according to maturity, see Figure 10.2. The classification includes the following categories: decided by the licensees for development or approved by the authorities for development (reserves), volumes dependent on clarification and decisions (contingent resources) and volumes expected to be discovered in the future (undiscovered resources). The main resource classes are thus reserves, contingent resources and undiscovered resources.

The detailed resource accounts as of 31 December 2009 are shown in Table 10.1 and in tables in Appendix 2.

Reserves

Reserves include remaining recoverable petroleum resources in deposits for which the authorities have approved the PDO, or granted a PDO exemption. Reserves also include petroleum resources in deposits that the licensees have decided to develop, but for which the authorities have not as yet completed the processing of either a PDO approval or a PDO exemption.

PDO approvals and decisions for improved recovery have resulted in reserve growth in 2009. However, significant reductions in reserves on several fields, among others Ormen Lange and Heidrun, resulted in a final reduction of 4 million scm o.e. in the gross gas and liquid reserves. Since 233 million scm o.e. were produced in 2009, resource accounts show a net reduction in the remaining reserves of 237 million scm o.e., corresponding to approximately seven per cent.

With regard to the authorities' goal of maturing 800 million scm of oil to reserves before 2015, 64 million scm of oil were entered as new reserves in 2009. In the period 2005 to 2009, the total growth of reserves has been 294 million scm o.e.

Contingent resources

Contingent resources include discovered quantities of petroleum for which a development decision has yet to be made. Contingent resources in fields, excluding resources from possible future measures to improve recovery (resource category 7A), increased by 98 million scm o.e. The reason for this increase is a general maturing of resources in projects on fields in 2009. The fields that have contributed most to this increase are Troll, Ekofisk and Eldfisk.

The estimate for contingent resources in discoveries has been reduced by 59 million scm o.e. to 716 million scm o.e. Although the increase in resources from new discoveries has been positive, the overall reduction can be attributed to the resources in the discoveries Goliat, Oselvar and 33/9-6 Delta maturing into reserves. In addition, the resource estimates for three discoveries in the Norwegian Sea and one discovery in the Barents Sea were, compared to last year's accounts, reduced by a total of 93 million scm.

The resource potential for possible future efforts to improve oil recovery (resource class 7A), is changed compared to last year. The estimate for oil is 160 million scm and the estimate for gas is 70 billion scm.

Undiscovered resources

Undiscovered resources include petroleum volumes expected to be present in defined plays, confirmed and unconfirmed, but which have not yet been proven by drilling (resource categories 8 and 9). The estimate for total undiscovered resources is reduced to 3.3 billion scm o.e. as a result of the estimate for the Barents Sea being reduced by 120 million scm o.e. compared to last year.

The North Sea

Production from the North Sea in 2009 totalled 155 million scm o.e. This includes a historical correction for condensate from Gungne, Sigyn, Sleipner Vest and Sleipner Øst. The growth in gross reserves was 70 million scm o.e. This resulted in remaining reserves in the North Sea being reduced by 85 million scm o.e. Contingent resources in fields increased by 108 million scm o.e as a result of, among other factors, several projects for improved recovery on Troll, Ekofisk, Eldfisk and Tor, which matured from resource category 7A to a more mature resource category. Contingent resources in discoveries increased by 72 billion scm o.e. as a result of increased resources from exploration and increased resource estimates for several of the discoveries in the North Sea. There have been 21 new discoveries in the North Sea in 2009.

The Norwegian Sea

Production from the Norwegian Sea in 2009 was 74 million scm o.e. As a result of a substantial reduction in reserves at Ormen Lange and Heidrun, the remaining reserves were reduced by 187 million scm o.e. compared to last year. Seven new discoveries were made in the Norwegian Sea in 2009. In spite of this, the estimate for contingent resources in discoveries has been reduced by 6 million scm o.e. compared to the accounts for last year. The reason is, among others, reduced resource estimates for 6406/9-1 Onyx and 6506/6-1 Victoria.

The Barents Sea

Production from the Barents Sea in 2009 was 4 million scm o.e.. Remaining reserves have increased by 34 million scm o.e., while contingent resources have been reduced by 126 million scm o.e. The changes are a result of, among other factors, the resources in Goliat maturing to reserves, and three discoveries being reclassified to resource category 6. There were no new discoveries in the Barents Sea in 2009.

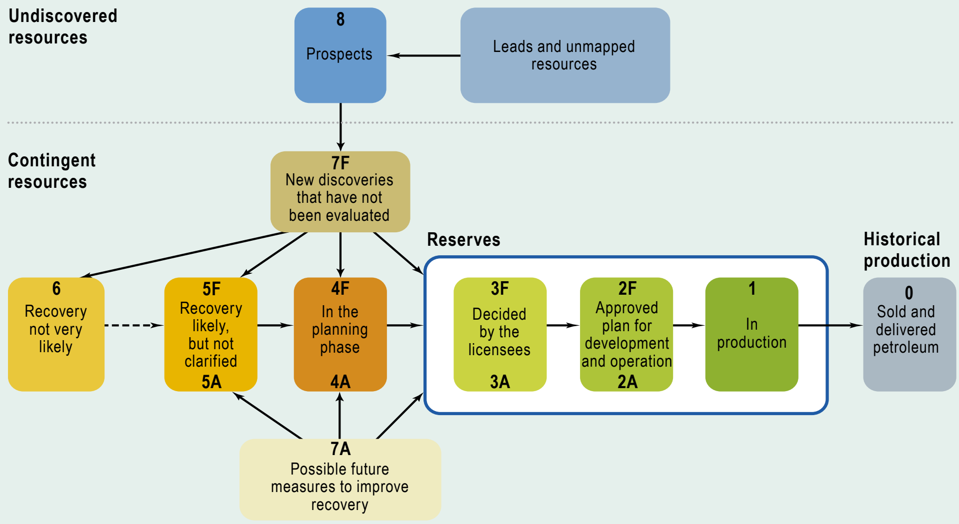


Figure 10.2 The NPD's resource classification
(Source: Norwegian Petroleum Directorate)

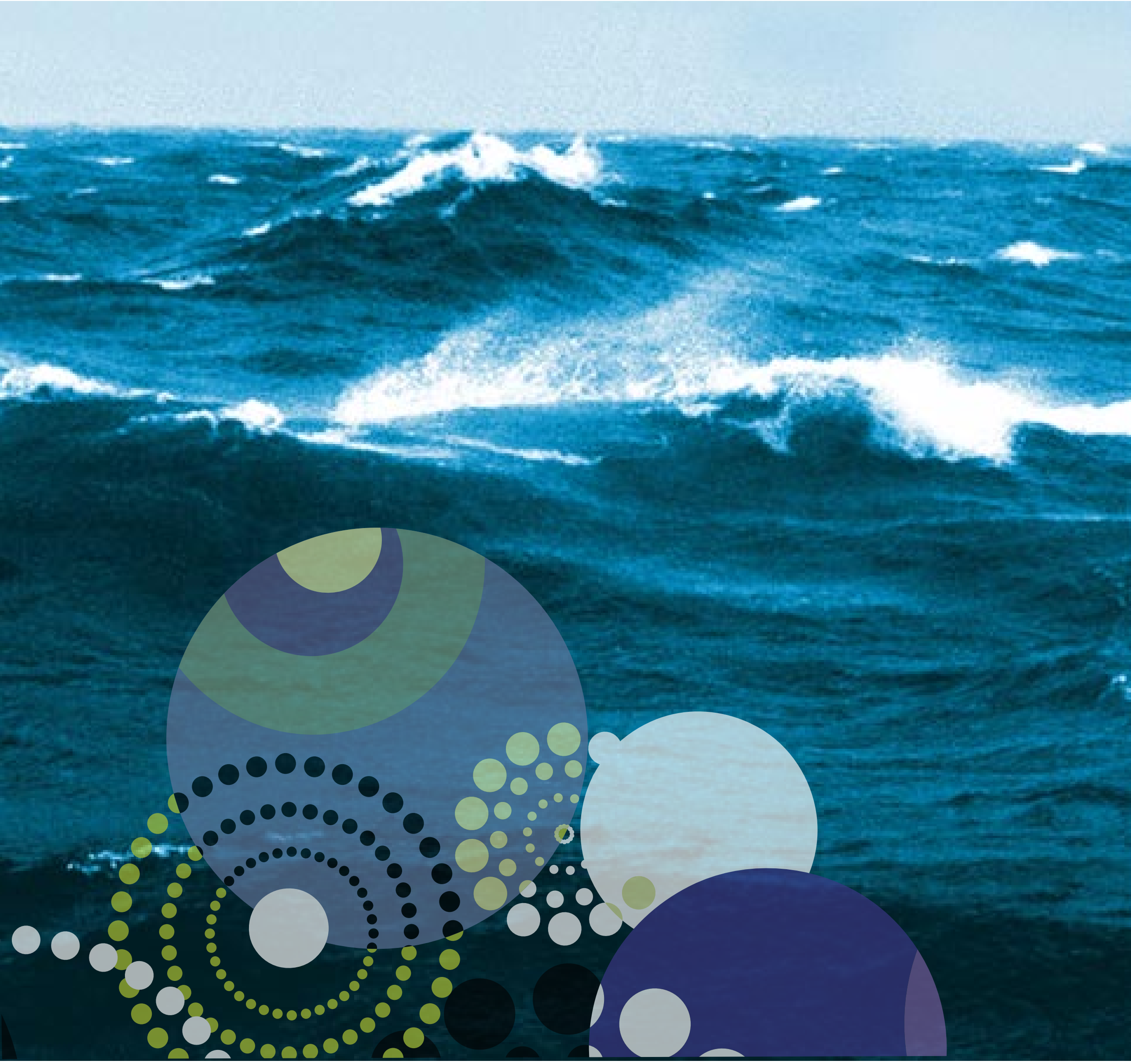
Table 10.1 Resource accounts per 31.12.2009

	Resource accounts per 31.12.2009					Changes from 2008				
Total recoverable potential	**Oil**	**Gas**	**NGL**	**Cond**	**Total**	**Oil**	**Gas**	**NGL**	**Cond**	**Total**
Project status category	mill scm	bill scm	mill tonnes	mill scm	mill scm o.e.	mill scm	bill scm	mill tonnes	mill scm	mill scm o.e.
Produced*	3521	1440	124	91	5287	116	107	8	-5	233
Remaining reserves**	868	2046	116	35	3169	-51	-170	-4	-8	-237
Contingent resources in fields	367	249	27	3	670	34	68	-1	-2	98
Contingent resources in discoveries	208	454	16	24	716	-3	-58	2	-3	-59
Potential from improved recovery***	160	70			230	15	-7	0	0	8
Undiscovered	1200	1825	0	255	3280	-60	-50	0	-10	-120
Total	**6324**	**6083**	**283**	**409**	**13353**	**50**	**-110**	**5**	**-28**	**-78**
North Sea										
Produced	3068	1263	99	66	4585	93	61	5	-8	155
Remaining reserves**	658	1366	65	3	2152	-50	-39	0	4	-85
Contingent resources in fields	327	176	13	1	529	41	69	0	-2	108
Contingent resources in discoveries	178	188	8	15	398	48	18	4	-1	72
Undiscovered	620	500		55	1175	0	0	0	0	0
Total	**4852**	**3494**	**186**	**141**	**8839**	**132**	**109**	**8**	**-6**	**250**
Norwegian Sea										
Produced	453	171	25	24	695	22	42	4	2	74
Remaining reserves**	179	517	44	15	796	-32	-135	-5	-12	-187
Contingent resources in fields	40	66	14	1	133	-7	1	-1	0	-8
Contingent resources in discoveries	29	218	8	5	267	8	-8	-1	-4	-6
Undiscovered	225	825		145	1195	5	0	0	-5	0
Total	**926**	**1797**	**90**	**191**	**3085**	**-3**	**-100**	**-3**	**-19**	**-127**
Barents Sea										
Produced	0	6	0	1	8	0	3	0	1	4
Remaining reserves**	31	162	6	17	222	31	4	0	-1	34
Contingent resources in fields	0	7	0	1	8	0	-1	0	0	-2
Contingent resources in discoveries	0	48	0	4	52	-59	-68	0	2	-126
Undiscovered	355	500		55	910	-65	-50	0	-5	-120
Total	**386**	**722**	**7**	**78**	**1199**	**-94**	**-112**	**0**	**-3**	**-209**

* *Include historical sale of gas from Tambar and an historical adjustment of condensate from Gungne, Sigyn, Sleipner Vest and Sleipner Øst.*
** *Includes resource categories 1, 2 and 3.*
*** *Resources from future measures for improved recovery are calculated for the total recoverable potential and have not been broken down by area.*

11

FIELDS IN PRODUCTION



Keys to tables in Chapters 11–13:

Participating interests in fields do not necessarily correspond with interests in the individual production licences, since unitised fields or fields for which the sliding scale has been exercised have a different composition of interests than the production licence. Interests are quoted with only two decimal places, so licensee holdings in some of the fields may not add up to 100 per cent. Participating interests are shown as of 31 December 2009.

"Original recoverable reserves" refers to reserves in resource categories 0, 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification, see figure 10.2.

"Recoverable reserves remaining at 31 December 2009" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

Resource Category 0: Petroleum sold and delivered
Resource Category 1: Reserves in production
Resource Category 2: Reserves with an approved plan for development and operation
Resource Category 3: Reserves which the licensees have decided to develop

Estimated production of oil is listed in barrels per day, while gas, NGL and condensate are listed in annual values.

Pictures and illustrations in Chapters 11 – 14:

We would like to thank the operators for the use of pictures and illustrations of facilities.

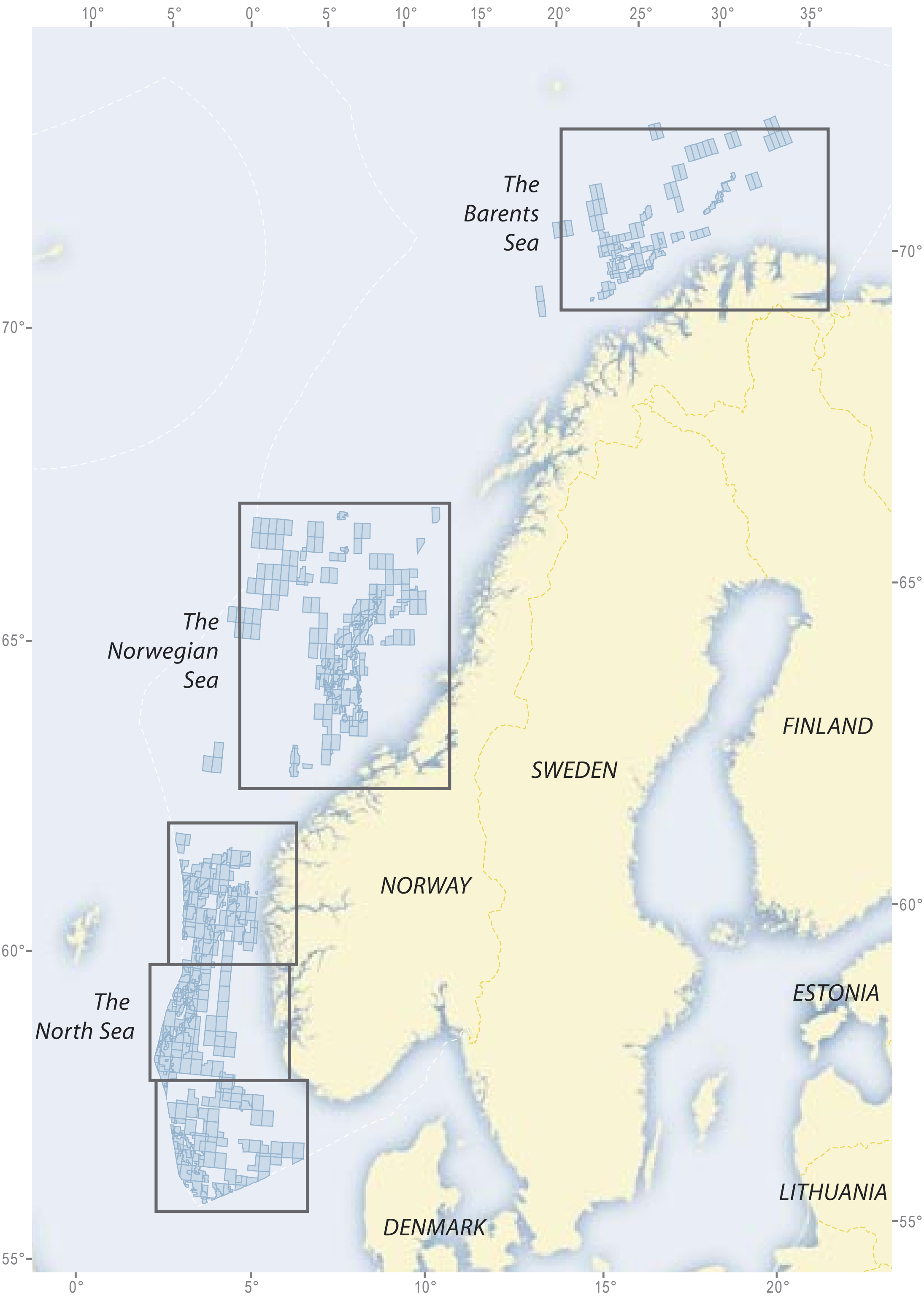


Figure 11.1 Areas on the Norwegian continental shelf
(Source: Norwegian Petroleum Directorate)

The southern part of the North Sea

The southern part of the North Sea is still an important petroleum province for Norway, 40 years after Ekofisk came on stream. Ekofisk is now the largest field on the Norwegian continental shelf, measured in daily production.
At present, there are 11 fields in production in the southern part of the North Sea. Two fields, Yme and Oselvar, are being developed. Seven fields have been shut down. One of them, Yme, is redeveloped and will start production again in the autumn of 2010. Facilities no longer in use are being removed. Ekofisk serves as a hub for petroleum operations in this area, with several fields utilising the infrastructure of Ekofisk for further transport in the Norpipe system. There are substantial remaining resources in the southern part of the North Sea, particularly in the large chalk fields in the very south of the area. Production of oil and gas is expected to continue from this area for as many as 40 more years.

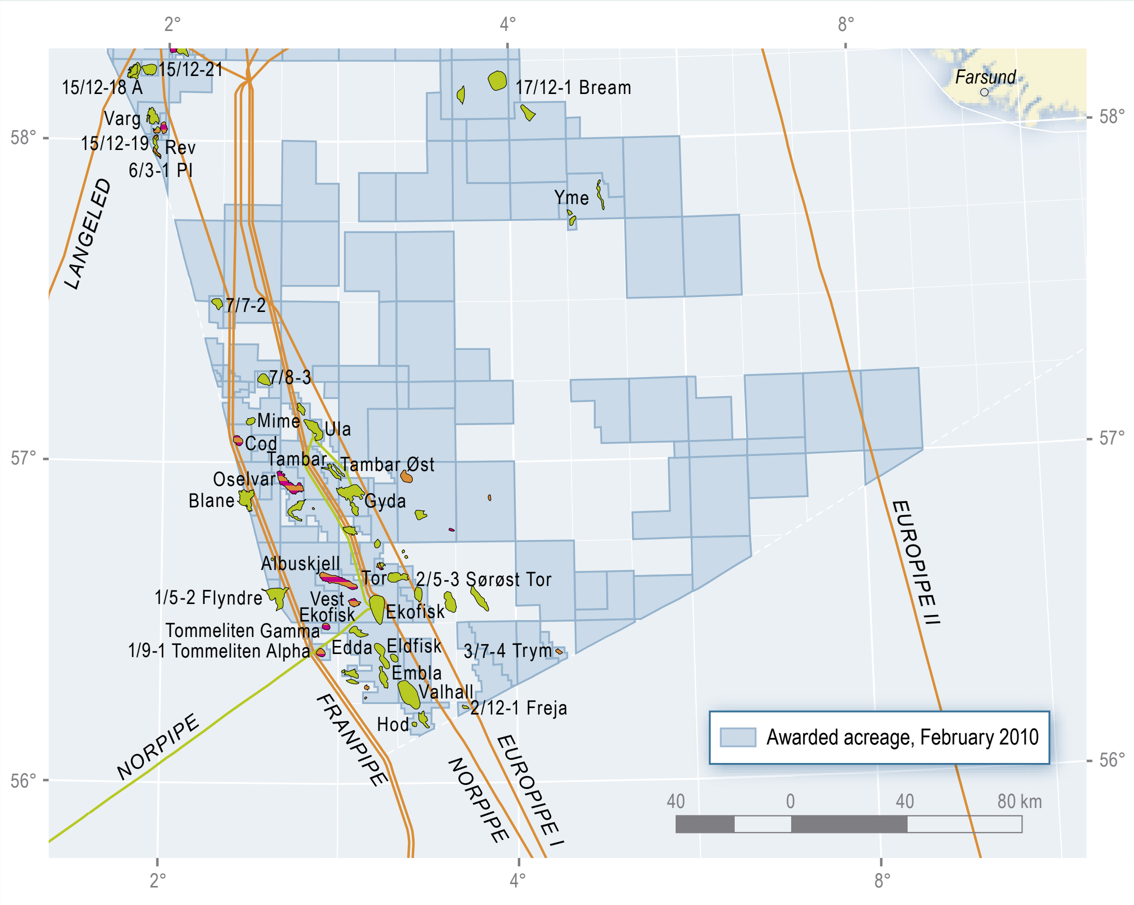


Figure 11.2 Fields and discoveries in the southern part of the North Sea
(Source: Norwegian Petroleum Directorate)

The middle part of the North Sea

The middle part of the North Sea has a long petroleum history. Balder, discovered in 1967, was the first oil discovery on the Norwegian continental shelf, but was not developed until 30 years later. The first development was the Frigg gas field, which was in production for almost 30 years, until it was shut down in 2004. At present 19 fields are in production in the middle part of the North Sea, and the development of several discoveries is in the planning stage. Six fields in the Frigg area have been shut down, and the facilities have been removed. It is possible that some of these will be redeveloped later. Heimdal has produced gas since 1985, and is now primarily a gas centre which performs processing services for other fields. The Sleipner field represents an important hub for the gas transportation system on the Norwegian continental shelf. Oil and gas from fields in the middle part of the North Sea is transported by tankers or by pipelines to onshore facilities in Norway and the United Kingdom.

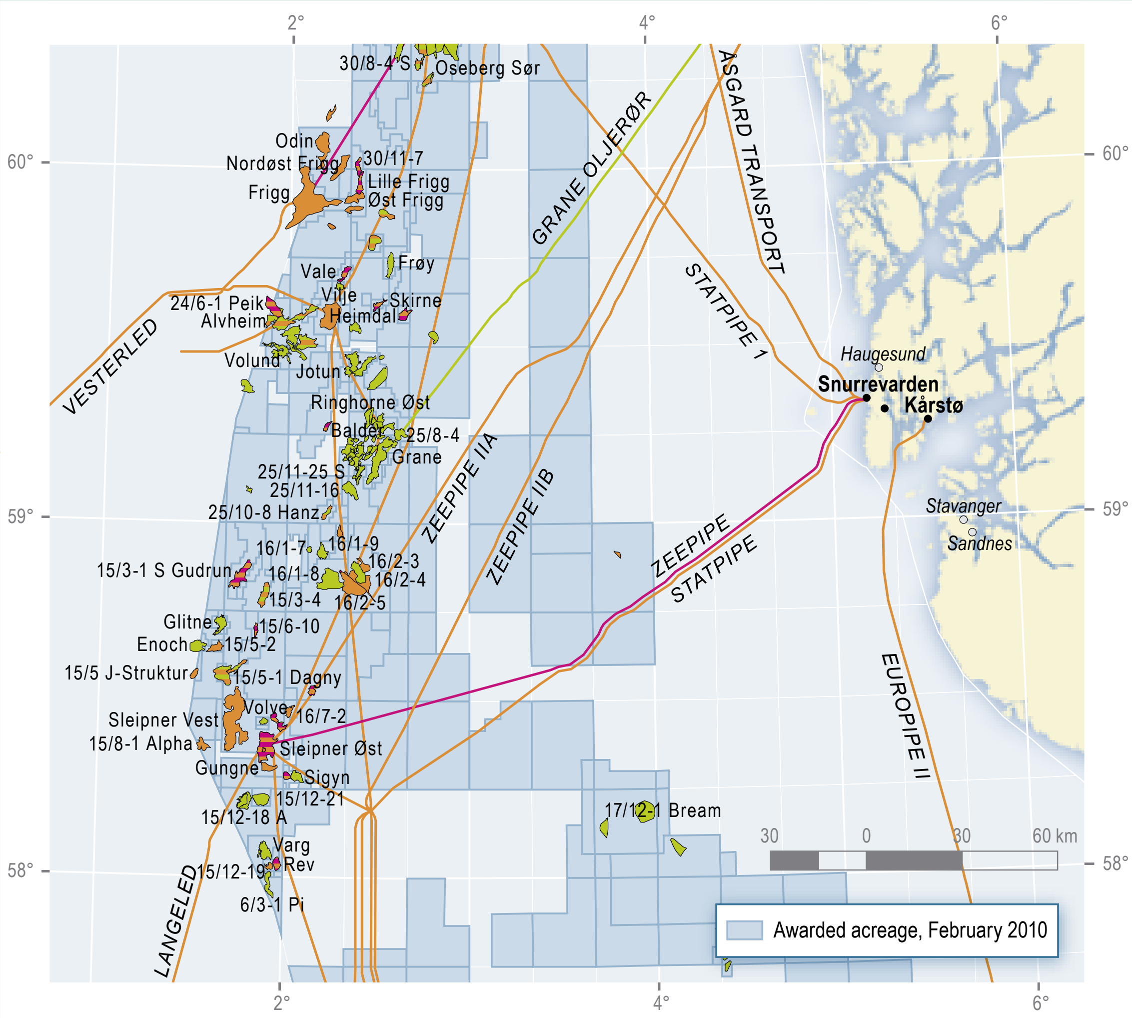


Figure 11.3 Fields and discoveries in the middle part of the North Sea
(Source: Norwegian Petroleum Directorate)

The northern part of the North Sea

The northern part of the North Sea encompasses two main areas, Tampen and Oseberg/Troll. At present 23 fields are in production in this part of the North Sea, and 3 are being developed; Gjøa, Vega and Vega Sør. The Tampen area has been producing for 30 years, but there is still a substantial resource potential, and production from this area is expected to continue for at least another 20 years. Statfjord is in late phase production of remaining gas, which is exported by pipeline to the United Kingdom. Troll plays a major role regarding gas supplies from the Norwegian continental shelf, and will remain the main source of Norwegian gas exports throughout this century. Oil production in the Oseberg area is declining, but the fields will continue to produce for many more years. Oil and gas from fields in the northern part of the North Sea is transported by tankers or by pipelines to land facilities in Norway and the United Kingdom.

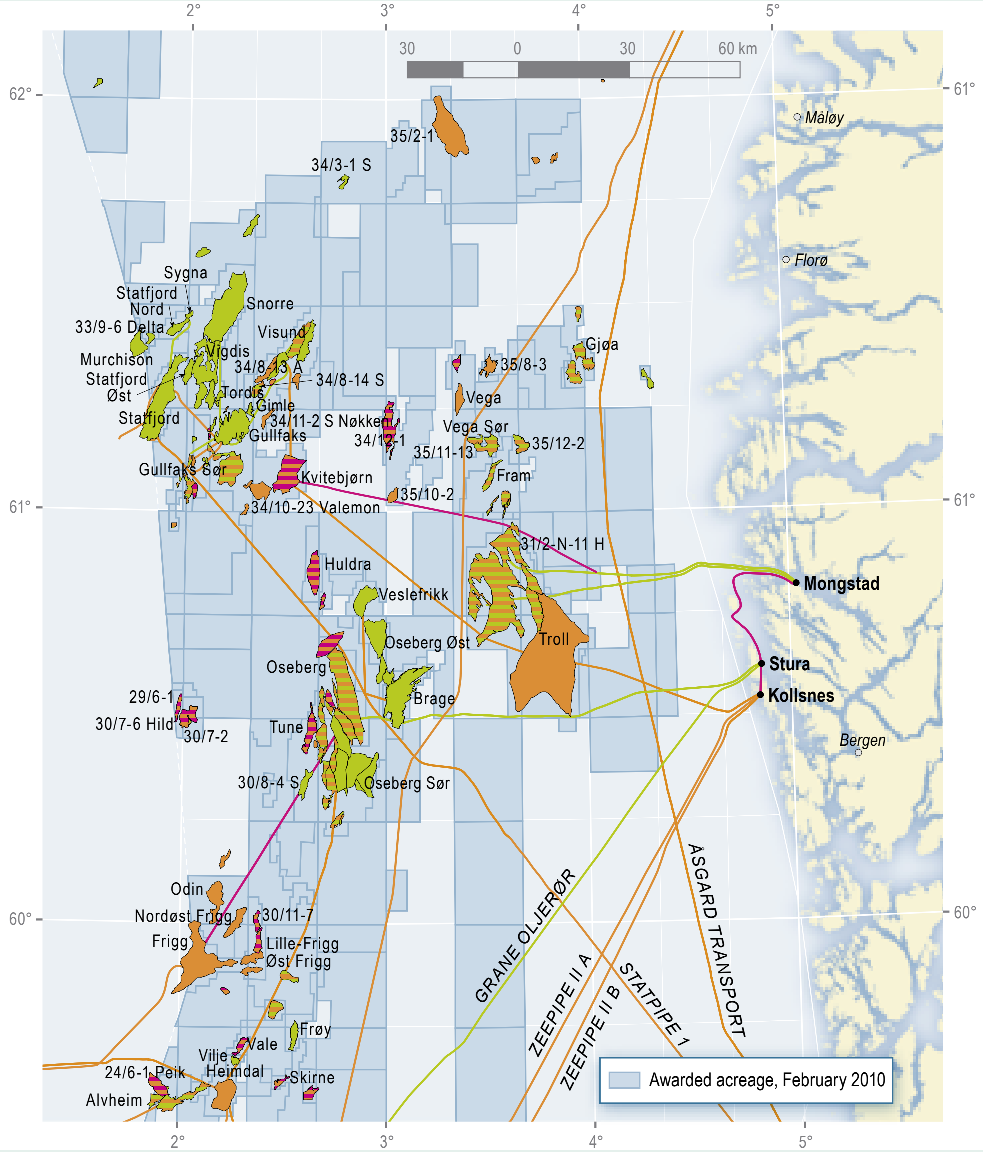


Figure 11.4 Fields and discoveries in the northern part of the North Sea
(Source: Norwegian Petroleum Directorate)

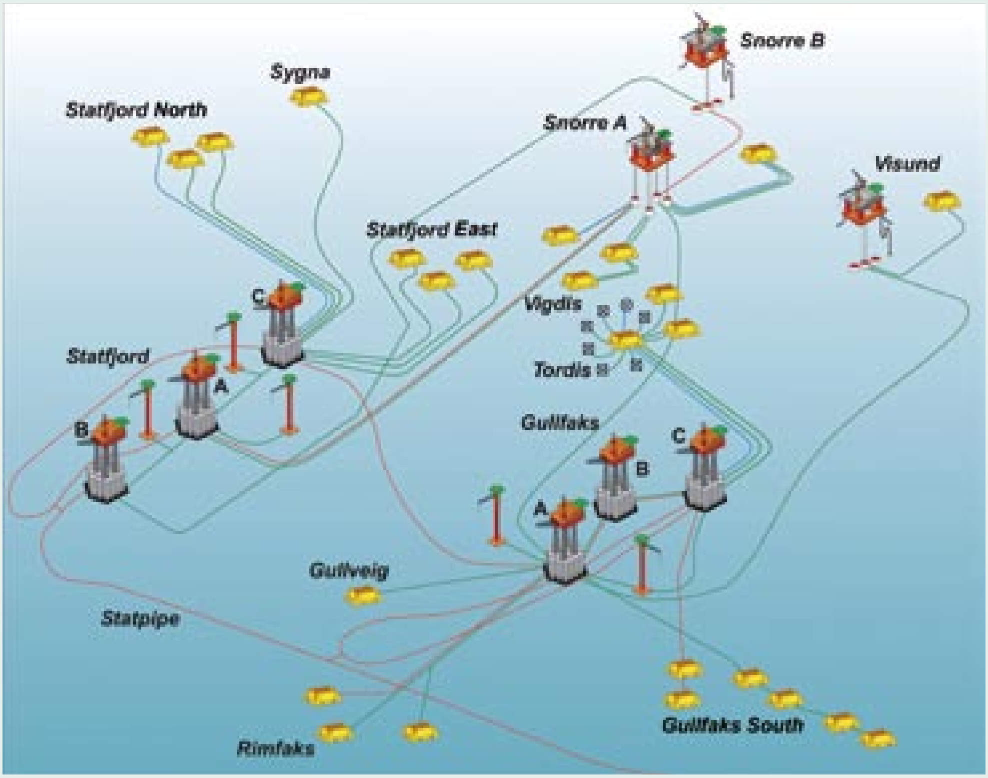


Figure 11.5 Facilities in the Tampen area
(Source: Statoil)

The Norwegian Sea

The Norwegian Sea is a less mature petroleum province than the North Sea. Draugen was the first field to come on stream, in 1993, and now 12 fields are producing in the Norwegian Sea after the development of Tyrihans and Alve. Two fields, Skarv and Morvin, are being developed. No fields have ceased production. There are significant gas reserves in the Norwegian Sea. The gas produced from the fields is transported in the Åsgard Transport pipeline to Kårstø in Rogaland and in Haltenpipe to Tjeldbergodden in Møre og Romsdal. Gas production from Ormen Lange is transported by pipeline to Nyhamna, and from there on to Easington in the United Kingdom. Oil from the fields in the Norwegian Sea is transported by tankers.

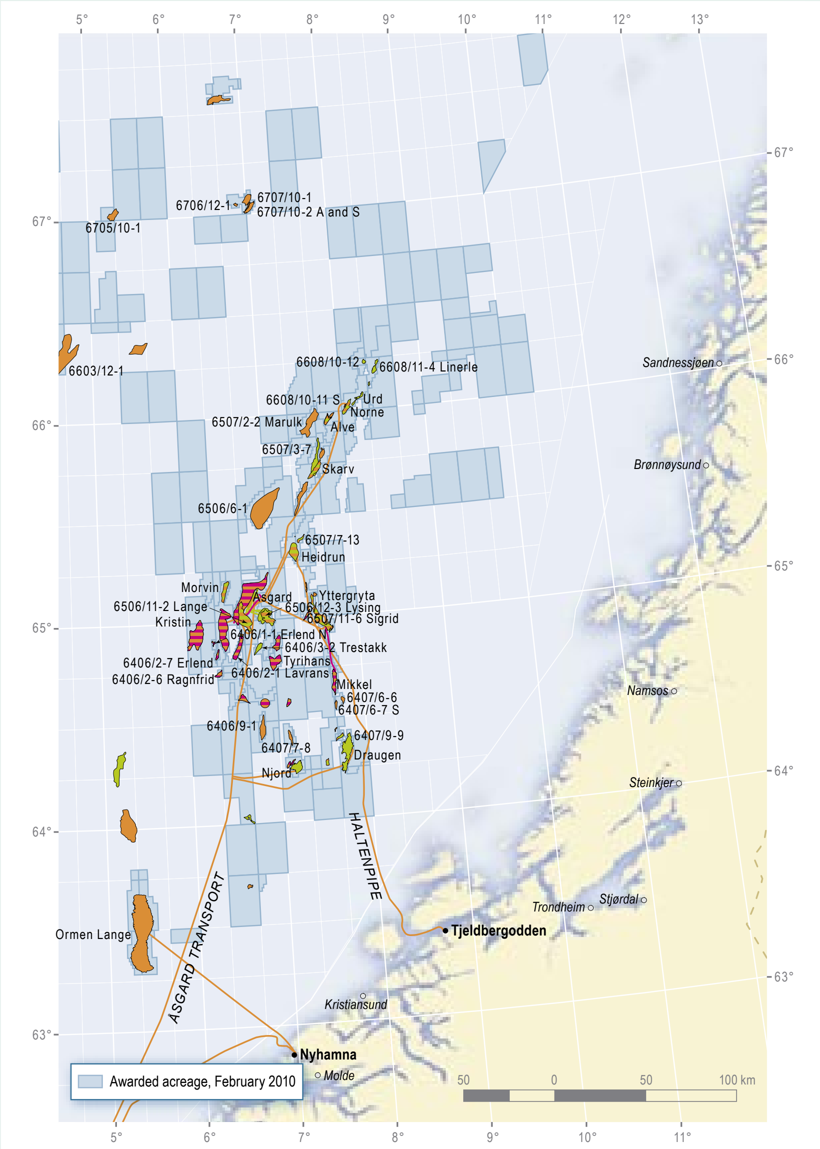


Figure 11.6 Fields and discoveries in the Norwegian Sea
(Source: Norwegian Petroleum Directorate)

The Barents Sea

The Barents Sea is considered as an immature petroleum province. Snøhvit is the only field developed so far, and came on stream in 2007. The gas from Snøhvit is transported by pipeline to Melkøya and further processed and liquefied to LNG, which is transported by special tankers to market. The development plan for Goliat was approved by the authorities in June 2009 and production start is planned for autumn 2013.

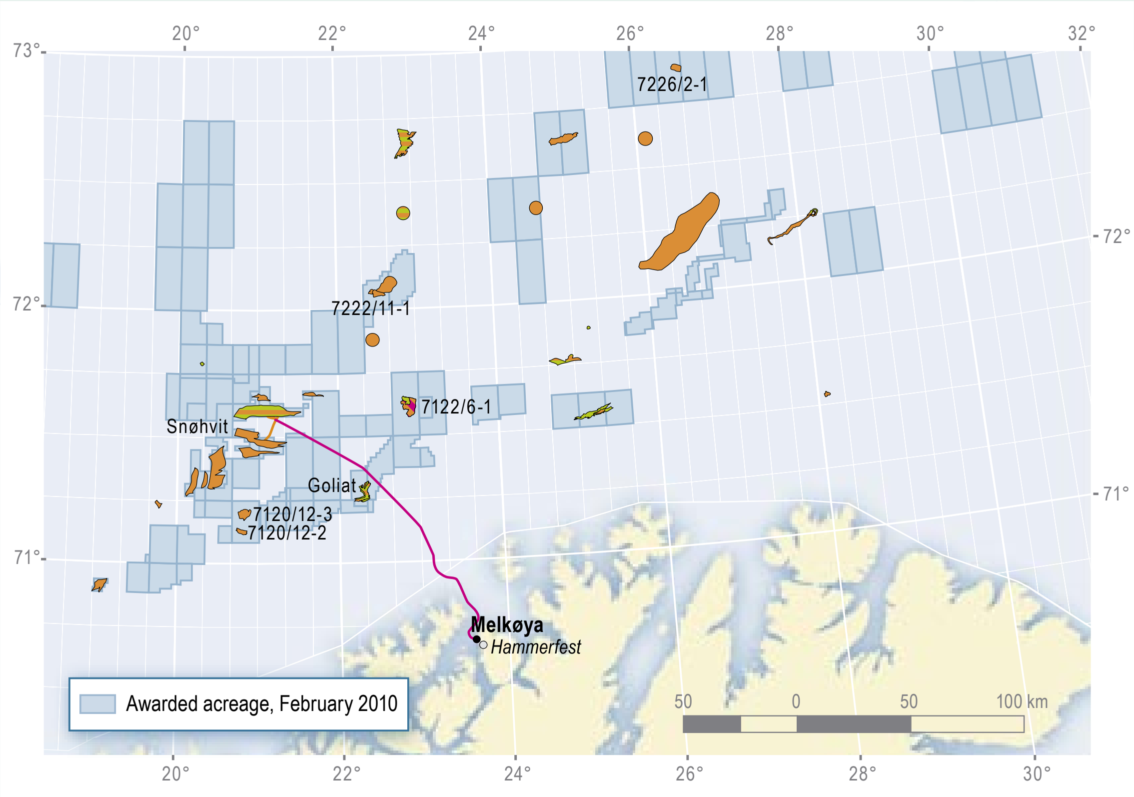
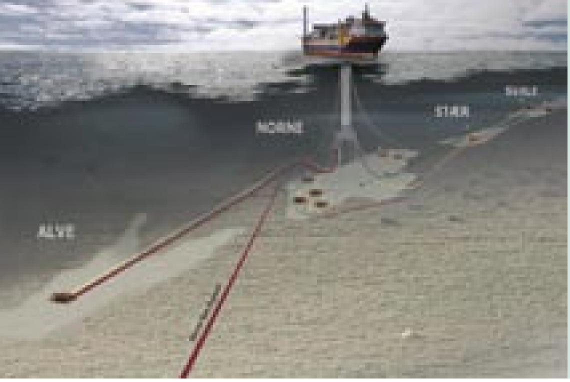
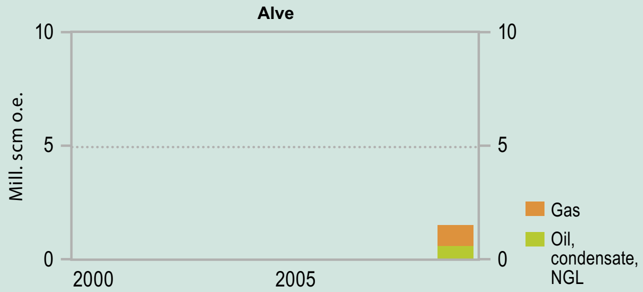


Figure 11.7 Fields and discoveries in the Barents Sea
(Source: Norwegian Petroleum Directorate)





Alve

Blocks and production licences	Block 6507/3 - production licence 159 B, awarded 2004	
Discovered	1990	
Development approval	16.03.2007 by the King in Council	
On stream	19.03.2009	
Operator	Statoil Petroleum AS	
Licensees	DONG E&P Norge AS	15.00 %
	Statoil Petroleum AS	85.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	1.0 million scm oil	0.7 million scm oil
	5.3 billion scm gas	4.4 billion scm gas
	1.0 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 5 000 barrels/day, Gas: 0.89 billion scm, NGL: 0.17 million tonnes	
Investment	Total investment is expected to be NOK 3.3 billion (2010 values)	
	NOK 3.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Harstad	

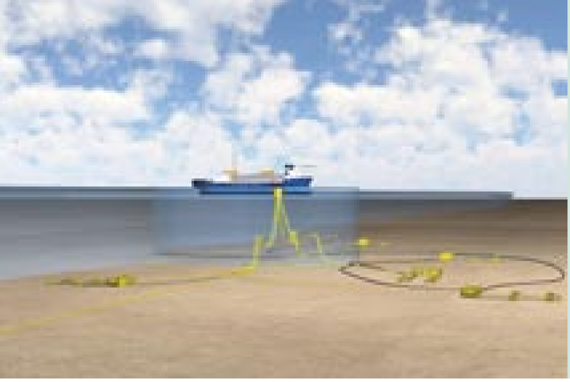
Development:
Alve is a gas and condensate field located about 16 kilometres southwest of Norne in the Norwegian Sea. The sea depth in the area is about 370 metres. The development concept is a standard subsea template with four well slots and one production well.

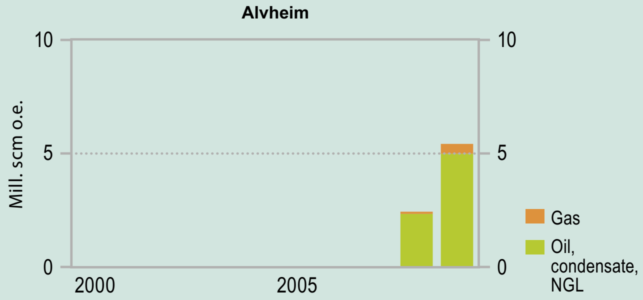
Reservoir:
The reservoir is in Jurassic sandstones of the Garn and Not Formations. The reservoir lies at a depth of about 3 600 metres. There are also resources in the Ile, Ror and Tilje Formations that may be developed later.

Recovery strategy:
The reservoir is produced by pressure depletion.

Transport:
Alve is tied to the Norne vessel by a pipeline. The gas is transported via the Norne pipeline to Åsgard Transport and further to Kårstø for export.

Status:
A new well is planned to determine production potential in the Tilje Formation.





Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS, awarded 2003	
	Block 24/6 - production licence 203, awarded 1996	
	Block 25/4 - production licence 036 C, awarded 2003	
	Block 25/4 - production licence 203, awarded 1996	
Discovered	1998	
Development approval	06.10.2004 by the King in Council	
On stream	08.06.2008	
Operator	Marathon Petroleum Norge AS	
Licensees	ConocoPhillips Skandinavia AS	20.00 %
	Lundin Norway AS	15.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	34.4 million scm oil	27.2 million scm oil
	7.9 billion scm gas	7.3 billion scm gas
Production	**Estimated production in 2010:**	
	Oil: 73 000 barrels/day, Gas: 0.47 billion scm	
Investment	Total investment is expected to be NOK 21.4 billion (2010 values)	
	NOK 17.7 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

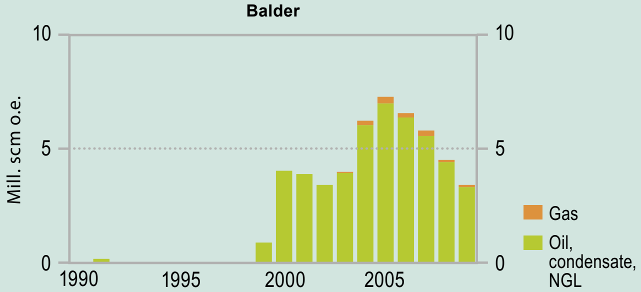
Development:
Alvheim is an oil and gas field located in the middle part of the North Sea, west of Heimdal and near the border to the British sector. The field includes three discoveries, 24/6-2 (Kamelon), 24/6-4 (Boa) and 25/4-7 (Kneler). The discovery 24/6-4 lies partly in the British sector. The sea depth in the area is 120 – 130 metres. The field is developed with a production vessel, «Alvheim FPSO», and subsea wells. The oil is stabilised and stored in the production vessel. The fields Vilje and Volund are tied to Alvheim.

Reservoir:
The reservoir consists of sandstones in the Heimdal Formation of Paleocene age. The sand was deposited as sub-marine fan deposits, lies at a depth of approximately 2 200 metres and has very good reservoir quality.

Recovery strategy:
Alvheim is produced by natural drive from a large surrounding aquifer.

Transport:
The oil is exported by tankers. Processed rich gas is transported by pipeline from Alvheim to the Scottish Area Gas Evacuation (SAGE) pipeline system on the British continental shelf.

Status:
Alvheim is producing beyond expectations and the resource estimates for the field have increased correspondingly. Several new development wells are planned. New discoveries made in the area can later be tied to Alvheim.



Balder

Blocks and production licences	Block 25/10 - production licence 028, awarded 1969 Block 25/11 - production licence 001, awarded 1965 Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 027 C, awarded 2000 Block 25/8 - production licence 169, awarded 1991
Discovered	1967
Development approval	02.02.1996 by the King in Council
On stream	02.10.1999
Operator	ExxonMobil Exploration & Production Norway AS
Licensees	ExxonMobil Exploration & Production Norway AS 100.00 %
Recoverable reserves	**Original:** 61.8 million scm oil; 1.8 billion scm gas **Remaining as of 31.12.2009:** 12.7 million scm oil; 0.7 billion scm gas
Production	**Estimated production in 2010:** Oil: 43 000 barrels/day, Gas: 0.12 billion scm
Investment	Total investment is expected to be NOK 33.2 billion (2010 values) NOK 31.0 billion have been invested as of 31.12.2009 (2010 values)
Operating organisation	Stavanger
Main supply base	Dusavik

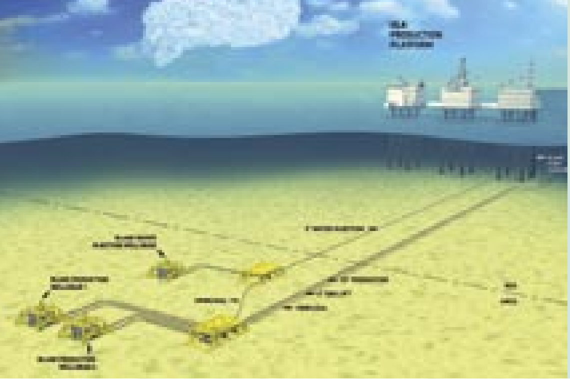
Development:
Balder is an oil field in the middle part of the North Sea, at a sea depth of 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, «Balder FPSO», where oil and gas are processed. The Ringhorne discovery, included in the Balder field, is developed with a combined accommodation, drilling and wellhead facility, tied back to the «Balder FPSO». The PDO for Ringhorne was approved on 11.05.2000 and production started on 21.05.2001. An amended PDO for Ringhorne was approved on 14.02.2003.

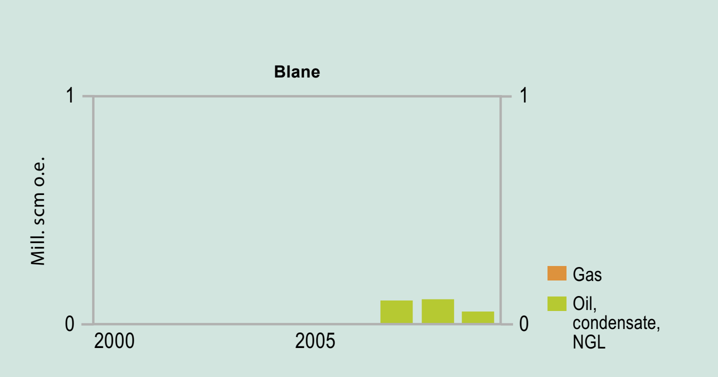
Reservoir:
The field contains several separate oil deposits in Eocene and Paleocene sandstones. The main reservoirs are in the Rogaland Group and belong to the Heimdal, Hermod and Ty Formations at a depth of about 1 700 metres. Ringhorne comprises several reservoirs of the same type as in Balder, with a main reservoir of Jurassic age containing oil and associated gas.

Recovery strategy:
Balder and Ringhorne produce primarily by natural aquifer drive, but some water injection for pressure support is utilised, especially at Ringhorne. Gas is also injected if the gas export system is down.

Transport:
Oil and gas from the Jurassic reservoir at Ringhorne are transported to Jotun for processing, while oil from the Rogaland Group is routed to Balder. Gas from «Balder FPSO» is transported to «Jotun FPSO», and then exported via Statpipe.
In periods with reduced gas export, excess gas may be injected in Balder.

Status:
The field is in decline phase, but it is assumed that it will continue producing until 2025. Studies have been started to evaluate possible means to improve recovery. A 4D seismic survey completed in 2009 will be analysed to evaluate new well locations. Five new production wells are being planned at both Ringhorne and Balder. These can start production from 2011-2014.





Blane

Blocks and production licences	Block 1/2 - production licence 143 BS, awarded 2003 The Norwegian part of the field is 18%, the British part is 82%	
Discovered	1989	
Development approval	01.07.2005	
On stream	12.09.2007	
Operator	Talisman Energy Norge AS	
Licensees	Talisman Energy Norge AS	18.00 %
	Bow Valley Petroleum (UK) Limited	12.50 %
	Eni UK Limited	13.90 %
	Eni ULX Limited	4.11 %
	Nippon Oil Exploration and Production UKl Limited	13.99 %
	Roc Oil (GB) Limited	12.50 %
	Talisman North Sea Limited	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
(Norwegian part)	0.9 million scm oil	0.6 million scm oil
Production	**Estimated production in 2010:** Oil: 2 000 barrels/day	
Investment	Total investment is expected to be NOK 0.6 billion (2010 values) NOK 0.6 billion have been invested as of 31.12.2009 (2010 values)	

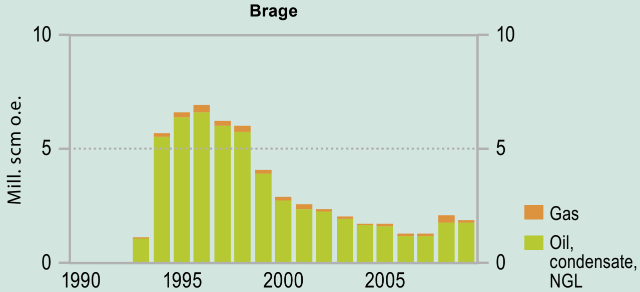
Development:
Blane is an oil field located southwest of Ula in the southern part of the North Sea, on the border to the British sector. The water depth in the area is about 70 metres. The field has been developed with a subsea facility tied to the Ula field. The subsea template is located on the British continental shelf.

Reservoir:
The reservoir is in marine Paleocene sandstones of the Forties Formation at a depth of approximately 3 100 metres.

Recovery strategy:
Blane is produced by pressure support from injection of produced water from Blane, Tambar and Ula. In addition, gas lift will be used in the wells.

Transport:
The wellstream is transported by pipeline to Ula for processing and metering. The oil is exported in existing pipeline to Teesside, while the gas is sold to Ula for injection in the Ula reservoir.

Status:
Water injection is temporarily inoperative. Gas lift started in February 2009, but has been discontinued because of leakage in the pipeline from Ula.



Brage

Blocks and production licences	Block 30/6 - production licence 053 B, awarded 1998	
	Block 31/4 - production licence 055, awarded 1979	
	Block 31/7 - production licence 185, awarded 1991	
Discovered	1980	
Development approval	29.03.1990 by the Storting	
On stream	23.09.1993	
Operator	Statoil Petroleum AS	
Licensees	Altinex Oil Norway AS	12.26 %
	Petoro AS	14.26 %
	Spring Energy Norway AS	2.50 %
	Statoil Petroleum AS	32.70 %
	Talisman Energy Norge AS	33.84 %
	VNG Norge AS	4.44 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	56.6 million scm oil	4.8 million scm oil
	3.7 billion scm gas	0.8 billion scm gas
	1.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 22 000 barrels/day, Gas: 0.09 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 28.5 billion (2010 values)	
	NOK 25.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

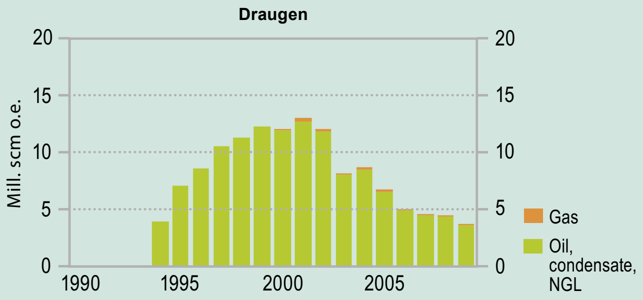
Development:
Brage is an oil field east of Oseberg in the northern part of the North Sea. The sea depth in the area is 140 metres. Brage has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket.

Reservoir:
The reservoir contains oil in sandstones of the Statfjord Formation of Early Jurassic age, and in the Brent Group and the Fensfjord Formation of Middle Jurassic age. There is also oil and gas in the Sognefjord Formation of Late Jurassic age. The reservoirs are at a depth of 2 000 – 2 300 metres. The reservoir quality varies from poor to excellent.

Recovery strategy:
The recovery mechanism in the Statfjord and Fensfjord Formations is water injection. Gas injection in the Sognefjord Formation started in March 2009. The first oil producers in the Brent Group started production in 2008, supported by water injection.

Transport:
The oil is transported by pipeline to Oseberg and on through the pipeline Oseberg Transport System (OTS) to the Sture terminal. A gas pipeline is tied back to Statpipe.

Status:
Brage is in the tail phase, but work is still in progress to find new ways of increasing recovery from the field. New wells have been drilled the past year and more wells are planned for the coming years. Adding chemicals to the injection water to improve water flow is one method that has been evaluated. A pilot project for microbiological injection (MEOR) is also planned.



Draugen

Blocks and production licences	Block 6407/9 - production licence 093, awarded 1984	
Discovered	1984	
Development approval	19.12.1988 by the Storting	
On stream	19.10.1993	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell	26.20 %
	BP Norge AS	18.36 %
	Chevron Norge AS	7.56 %
	Petoro AS	47.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	145.0 million scm oil	19.7 million scm oil
	1.6 billion scm gas	0.1 billion scm gas
	2.7 million tonnes NGL	0.6 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 46 000 barrels/day, Gas: 0.04 billion scm, NGL: 0.08 million tonnes	
Investment	Total investment is expected to be NOK 40.4 billion (2010 values) NOK 36.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

Development:
Draugen is an oil field in the Norwegian Sea at a sea depth of 250 metres. The field has been developed with a concrete fixed facility and integrated topside. Stabilised oil is stored in tanks in the base of the facility. Two pipelines transport the oil from the facility to a floating loading buoy. The Garn Vest and Rogn Sør deposits have been developed with a total of seven subsea wells connected to the main facility at Draugen. The field also has six subsea water injection wells, of these only two are being used.

Reservoir:
The main reservoir is in sandstones belonging to the Rogn Formation of Late Jurassic age. The Garn Formation of Middle Jurassic age in the western part of the field is also producing. The reservoirs lie at a depth of about 1 600 metres and are relatively homogenous, with good reservoir characteristics.

Recovery strategy:
The field is produced by pressure maintenance from water injection and aquifer support.

Transport:
The oil is exported by tankers via a floating loading buoy. The associated gas is transported by the Åsgard Transport pipeline to Kårstø. In periods without gas export, excess gas can be injected in a separate structure east of Draugen.

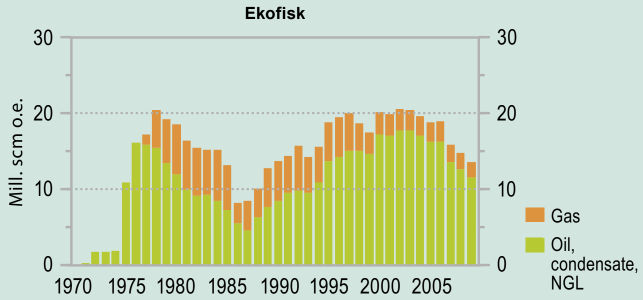
Status:
Several measures to increase oil recovery have been evaluated. Based on a 4D seismic survey carried out in 2009, the potential of new wells on the field is being evaluated. The discovery 6407/9-9 (Hasselmus) is planned to be phased in to the Draugen facility, and a decision regarding development is expected in 2010. Gas from this deposit will be utilised as fuel gas on Draugen.

Ekofisk

Blocks and production licences	Block 2/4 - production licence 018, awarded 1965	
Discovered	1969	
Development approval	01.03.1972	
On stream	15.06.1971	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	Statoil Petroleum AS	7.60 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	532.6 million scm oil	118.5 million scm oil
	156.5 billion scm gas	18.8 billion scm gas
	14.6 million tonnes NGL	2.0 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 176 000 barrels/day, Gas: 1.72 billion scm, NGL: 0.23 million tonnes	
Investment	Total investment is expected to be NOK 222.8 billion (2010 values)	
	NOK 167.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Ekofisk is an oil field located in the southern part of the North Sea. The sea depth in the area is 70 - 75 metres. The field was initially produced to tankers until a concrete storage tank was installed in 1973. Since then, the field has been further developed with many facilities, including riser facilities for associated fields and export pipelines. Several of these have been decommissioned and are awaiting disposal. Today, the operative parts of the Ekofisk Centre consist of the accommodation facilities, Ekofisk H and Ekofisk Q, the production facility Ekofisk C, the drilling and production facility Ekofisk X, the processing facility Ekofisk J and the production and processing facility Ekofisk M. From the wellhead facility Ekofisk A, located in the southern part of the field, production goes to the riser facility Ekofisk FTP for processing at the Ekofisk Centre. The pipeline from Ekofisk B in the northern part of the field is routed to Ekofisk M. Ekofisk K is a facility for water injection. A plan for water injection at Ekofisk was approved on 20.12.1983, a PDO for Ekofisk II was approved on 09.11.1994 and a PDO for Ekofisk Growth was approved on 06.06.2003. In June 2008 a subsea template for water injection wells was approved. These will replace the water injection at Ekofisk W, which is no longer in use. In March 2010, the new accommodation facility, Ekofisk L, was approved. This will replace Ekofisk H and Ekofisk Q. Ekofisk L will be in operation from autumn 2013. Permanent cables are now being installed on the seabed over the Ekofisk reservoir for acquisition of seismic data.

Reservoir:
The Ekofisk field produces from naturally fractured chalk of the Ekofisk and Tor Formations of Early Paleocene and Late Cretaceous ages. The reservoir rocks have high porosity, but low permeability. The reservoir has an oil column of more than 300 metres and lies 2 900 - 3 250 metres below sea level.



Recovery strategy:
Ekofisk was originally developed by pressure depletion and had an expected recovery factor of 17 per cent. Since then, limited gas injection and comprehensive water injection have contributed to a substantial increase in oil recovery. Large scale water injection started in 1987, and in subsequent years the water injection area has been extended in several phases. Experience has proven that water displacement of the oil is more effective than expected, and the expected recovery factor for Ekofisk is now approximately 50 per cent. In addition to the water injection, compaction of the soft chalk provides extra force to the drainage of the field. The reservoir compaction has resulted in subsidence of the seabed, which is now more than 9 metres in the central part of the field. It is expected that the subsidence will continue for many years, but at a lower rate.

Transport:
Oil and gas are routed to export pipelines via the processing facility at Ekofisk J. Gas from the Ekofisk area is transported via the Norpipe Gas pipeline to Emden, while the oil, which also contains NGL fractions, is sent via the Norpipe Oil pipeline to Teesside.

Status:
Production from Ekofisk is maintained at a high level through continuous drilling of water injection and production wells from several facilities. Further development of the southern part of the field is being considered. Two new installations are planned, Ekofisk Z which is a production facility, and Ekofisk VB, a subsea template for water injection wells. PDO is expected in 2011.

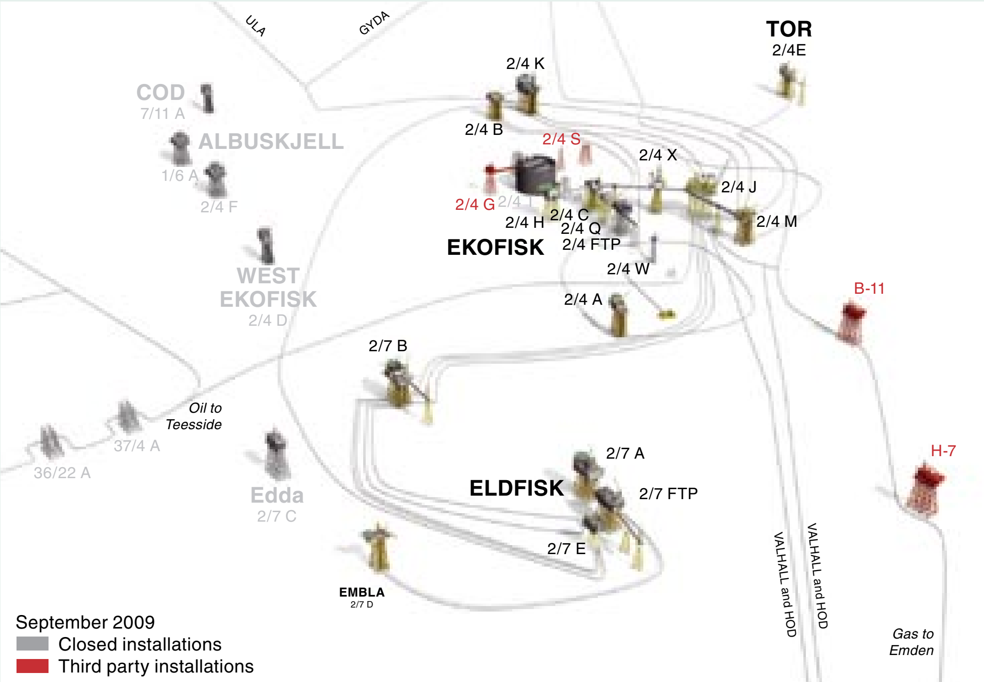
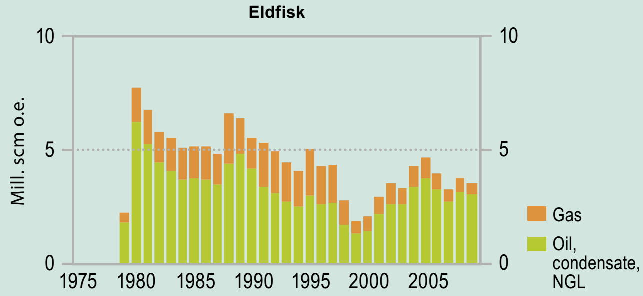


Figure 11.8 Facilites in the Ekofisk area
(Source: ConocoPhillips)



Eldfisk

Blocks and production licences	Block 2/7 - production licence 018, awarded 1965	
Discovered	1970	
Development approval	25.04.1975	
On stream	08.08.1979	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	Statoil Petroleum AS	7.60 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	132.2 million scm oil	40.0 million scm oil
	44.0 billion scm gas	5.9 billion scm gas
	4.0 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 51 000 barrels/day, Gas: 0.50 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 107.1 billion (2010 values)	
	NOK 65.6 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

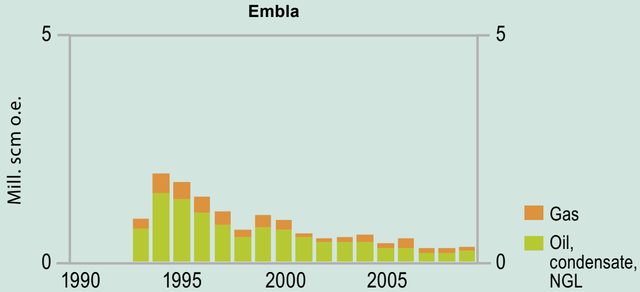
Development:
Eldfisk is an oil field located south of Ekofisk, in the southern part of the North Sea. The sea depth in the area is 70 - 75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and Eldfisk FTP are wellhead and process facilities connected by a bridge. Eldfisk A also has drilling facilities. In 1999, a new water injection facility, Eldfisk E, was installed. The facility also supplies the Ekofisk field with some injection water through a pipeline from Eldfisk to Ekofisk K. The Embla field, located south of Eldfisk, is tied to Eldfisk FTP.

Reservoir:
The Eldfisk field produces from the Ekofisk, Tor and Hod Formations from the Early Paleocene and Late Cretaceous ages. The reservoir rock is fine-grained and dense, but with high porosity. Natural fracturing allows the reservoir fluids to flow more easily. The field consists of three structures: Alpha, Bravo and Øst Eldfisk. The reservoir lies at a depth of 2 700 - 2 900 metres.

Recovery strategy:
Eldfisk was originally developed by pressure depletion. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in periods when export is not possible. Pressure depletion has caused compaction in the reservoir, which has resulted in a few metres of seabed subsidence.

Transport:
Oil and gas are sent to the export pipelines through the Ekofisk Centre. Gas from the Ekofisk area is sent by pipeline to Emden, while the oil, which also contains NGL fractions, is routed by pipeline to Teesside.

Status:
For several years, it has been carried out work to plan a new development which is necessary for the production to continue in the future. The current plan is to build a new combined accommodation, wellhead and process facility, Eldfisk S, bridge-connected to Eldfisk E. PDO is planned in 2011 and the new facility will replace several functions of Eldfisk A and Eldfisk FTP.



Embla

Blocks and production licences	Block 2/7 - production licence 018, awarded 1965	
Discovered	1988	
Development approval	14.12.1990 by the King in Council	
On stream	12.05.1993	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35.11 %
	Eni Norge AS	12.39 %
	Petoro AS	5.00 %
	Statoil Petroleum AS	7.60 %
	Total E&P Norge AS	39.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	10.4 million scm oil	0.5 million scm oil
	4.1 billion scm gas	0.7 billion scm gas
	0.5 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 2 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 5.4 billion (2010 values)	
	NOK 5.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

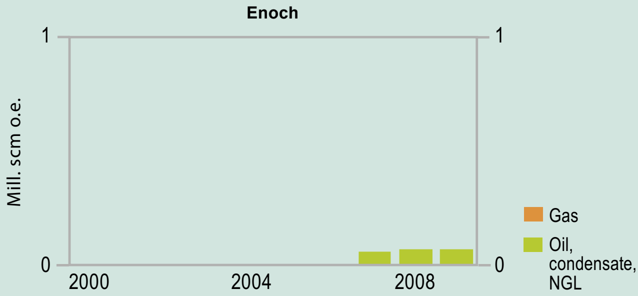
Development:
Embla is an oil field located close to Eldfisk in the southern part of the North Sea. The field has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The sea depth in the area is 70 – 75 metres. The amended PDO for Embla was approved on 25.04.1995.

Reservoir:
The Embla field produces from a segmented sandstone reservoir of Devonian age. The reservoir is complex and lies at a depth of more than 4 000 metres. Embla was the first field with high pressure and high temperature to be developed in the area.

Recovery strategy:
Embla is produced by pressure depletion.

Transport:
Oil and gas are transported to Eldfisk for processing and on to the Ekofisk Centre for export. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, which also contains NGL fractions, is routed by pipeline to Teesside.

Status:
In the long-term, new wells may be drilled at Embla if the lifetime of Eldfisk is extended.



Enoch

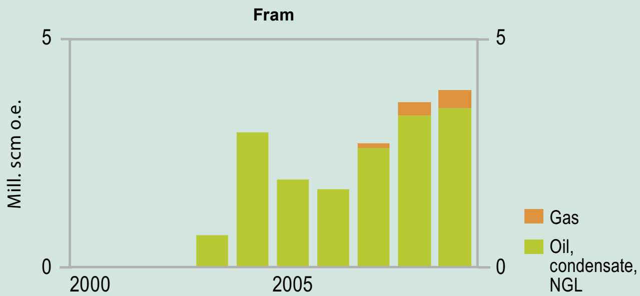
Blocks and production licences	Block 15/5 - production licence 048 D, awarded 2005 The Norwegian part of the field is 20%, the British part is 80%	
Discovered	1985	
Development approval	01.07.2005	
On stream	31.05.2007	
Operator	Talisman North Sea Limited	
Licensees	Altinex Oil Norway AS	4.36 %
	DONG E&P Norge AS	1.86 %
	Det norske oljeselskap ASA	2.00 %
	Statoil Petroleum AS	11.78 %
	Bow Valley Petroleum (UK) Limited	12.00 %
	Dana Petroleum (E & P) Limited	8.80 %
	Dyas UK Limited	14.00 %
	Endeavour Energy (UK) Limited	8.00 %
	Roc Oil (GB) Limited	12.00 %
	Talisman LNS Limited	1.20 %
	Talisman North Sea Limited	24.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
(Norwegian part)	0.5 million scm oil	0.3 million scm oil
Production	**Estimated production in 2010:** Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 0.3 billion (2010 values) NOK 0.3 billion have been invested as of 31.12.2009 (2010 values)	

Development:
Enoch is located in the middle part of the North Sea on the border to the British sector, just northwest of Sleipner. The field has been developed with a subsea facility on the British continental shelf and is tied to the British field Brae.

Reservoir:
The reservoir, containing oil, is in sandstones of Paleocene age at a depth of approximately 2 100 metres. The reservoir quality is varying.

Recovery strategy:
The field is recovered by pressure depletion, but water injection may be implemented at a later stage.

Transport:
The wellstream from Enoch is transported to the Brae A facility for processing and further transport in pipeline to Cruden Bay. The gas is sold to Brae.



Fram

Blocks and production licences	Block 35/11 - production licence 090, awarded 1984	
Discovered	1992	
Development approval	23.03.2001 by the King in Council	
On stream	02.10.2003	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	25.00 %
	GDF SUEZ E&P Norge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	Statoil Petroleum AS	45.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	25.7 million scm oil	9.3 million scm oil
	8.5 billion scm gas	7.7 billion scm gas
	0.5 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 45 000 barrels/day, Gas: 0.58 billion scm, NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 12.6 billion (2010 values)	
	NOK 12.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

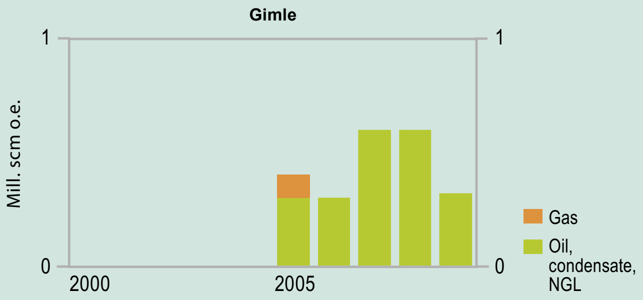
Development:
Fram is an oil field located in the northern part of the North Sea, about 20 kilometres north of Troll. The sea depth in the area is approximately 350 metres. The field comprises two deposits, Fram Vest and Fram Øst. The Fram Vest deposit is developed by two subsea templates tied back to Troll C. The gas is separated from the liquid on Troll C and re-injected into the Fram Vest reservoir. The development of the Fram Øst deposit was approved on 22.04.2005. This development includes two subsea templates tied back to Troll C. Production from Fram Øst started in October 2006.

Reservoir:
The reservoirs in Fram Vest and Fram Øst consist partly of Upper Jurassic sandstones in the Draupne Formation and shallow marine sandstones in the Sognefjord Formation, and partly of sandstones of the Brent Group of Middle Jurassic age. The reservoirs are in several isolated rotated fault blocks and contain oil with an overlying gas cap. The reservoir depth is 2 300 - 2 500 metres. The reservoir in the Fram Vest deposit is complex while the reservoirs in the Fram Øst deposit are generally of good quality.

Recovery strategy:
The Fram Vest deposit is produced by gas injection as pressure support. Gas export from Fram started in the autumn of 2007, and was increased in 2009. The Fram Øst deposit in the Sognefjord Formation is produced by injection of produced water as pressure support, in addition to natural aquifer drive. The Brent reservoir in the Fram Øst deposit is recovered by pressure support from natural aquifer drive. Gas lift will also be used in the wells. Oil production from Fram is balanced in proportion to gas production capacity at Troll C.

Transport:
The Fram wellstream is transported by pipeline to Troll C for processing. The oil is then transported to Mongstad through the Troll Oljerør II pipeline. Gas which is not injected is exported via Troll A to Kollsnes.

Status:
Additional resources have been proven in new deposits near the field. These are being considered for further development of Fram.



Gimle

Blocks and production licences	Block 34/10 - production licence 050 DS, awarded 2006 Block 34/7 - production licence 120 B, awarded 2006 Block 34/8 - production licence 120 B, awarded 2006	
Discovered	2004	
Development approval	18.05.2006	
On stream	19.05.2006	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	5.79 %
	Petoro AS	24.19 %
	Statoil Petroleum AS	65.13 %
	Total E&P Norge AS	4.90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	3.4 million scm oil	1.4 million scm oil
	0.9 billion scm gas	0.8 billion scm gas
	0.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 5 000 barrels/day.	
Investment	Total investment is expected to be NOK 1.0 billion (2010 values) NOK 0.9 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	

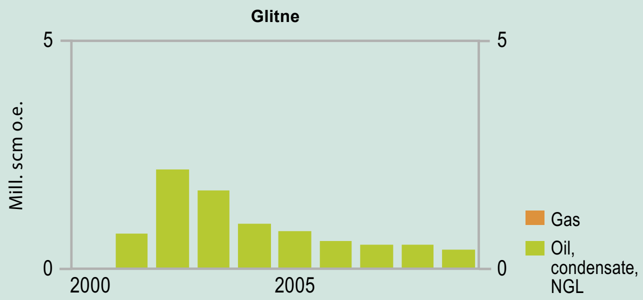
Development:
Gimle is a small oil field in the northern part of the North Sea. The sea depth in the area is about 220 metres. The field is tied to the Gullfaks C facility by two production wells and one water injection well drilled from Gullfaks C.

Reservoir:
The reservoir consists of sandstones of the Tarbert Formation of Middle Jurassic age, in a downfaulted structure northeast of Gullfaks. There are also slumped sands of Late Jurassic age. The reservoir depth is about 2 900 metres, and the reservoir has good quality.

Recovery strategy:
The field is recovered by pressure support from water injection.

Transport:
The production from Gimle is processed on the Gullfaks C facility and transported together with oil and gas from Gullfaks.

Status:
The drilling of new wells is being considered in longer term.



Glitne

Blocks and production licences	Block 15/5 - production licence 048 B, awarded 2001	
	Block 15/6 - production licence 029 B, awarded 2001	
Discovered	1995	
Development approval	08.09.2000 by the Crown Prince Regent in Council	
On stream	29.08.2001	
Operator	Statoil Petroleum AS	
Licensees	Det norske oljeselskap ASA	10.00 %
	Faroe Petroleum Norge AS	9.30 %
	Statoil Petroleum AS	58.90 %
	Total E&P Norge AS	21.80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	8.6 million scm oil	0.2 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 8 000 barrels/day.	
Investment	Total investment is expected to be NOK 3.2 billion (2010 values)	
	NOK 3.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

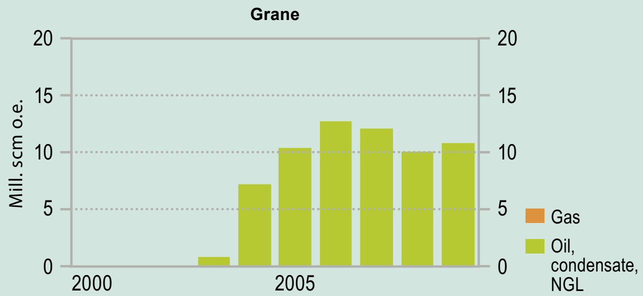
Development:
Glitne is an oil field in the middle part of the North Sea, 40 kilometres north of the Sleipner area. The sea depth in the area is about 110 metres. The field is developed with six horizontal production wells and one water injection well, tied back to the production and storage vessel “Petrojarl 1”.

Reservoir:
The reservoir consists of several separate sand lobes deposited as deep marine fans in the upper part of the Heimdal Formation of Paleocene age. The reservoir lies at a depth of approximately 2 150 metres.

Recovery strategy:
Glitne is recovered by pressure support from a large natural aquifer in the Heimdal Formation. Associated gas is used for gas lift in the horizontal wells.

Transport:
Oil from Glitne is processed and stored on the production vessel and exported by tankers. Excess gas is injected in the Utsira Formation.

Status:
It is expected that production from the field will cease late in 2010, but the drilling of a new well in 2010 is still being considered.



Grane

Blocks and production licences	Block 25/11 - production licence 001, awarded 1965	
	Block 25/11 - production licence 169 B1, awarded 2000	
Discovered	1991	
Development approval	14.06.2000 by the Storting	
On stream	23.09.2003	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	6.17 %
	ExxonMobil Exploration & Production Norway AS	28.22 %
	Petoro AS	28.94 %
	Statoil Petroleum AS	36.66 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	116.7 million scm oil	53.1 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 160 000 barrels/day.	
Investment	Total investment is expected to be NOK 30.6 billion (2010 values)	
	NOK 22.9 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Grane is an oil field located east of the Balder field in the middle part of the North Sea. The sea depth is 128 metres. The field has been developed with an integrated accommodation, drilling and processing facility with a fixed steel jacket. The facility has 40 well slots.

Reservoir:
The field consists of one main reservoir structure and some additional segments. The reservoir consists mostly of sandstones in the Heimdal Formation of Paleocene age with very good reservoir characteristics. The reservoir lies at a depth of approximately 1 700 metres, and there is full communication in the reservoir. The oil has high viscosity.

Recovery strategy:
The recovery mechanism is gas injection at the top of the structure, and horizontal production wells at the bottom of the oil zone. Four water injection wells are planned later in the production period.

Transport:
Oil from Grane is sent by pipeline to the Sture terminal for storage and export. Injection gas is imported to Grane through a pipeline from the Heimdal facility.

Status:
Several new wells are being planned, most of them as multi-lateral wells. The first two water injection wells are planned to be drilled in 2010.

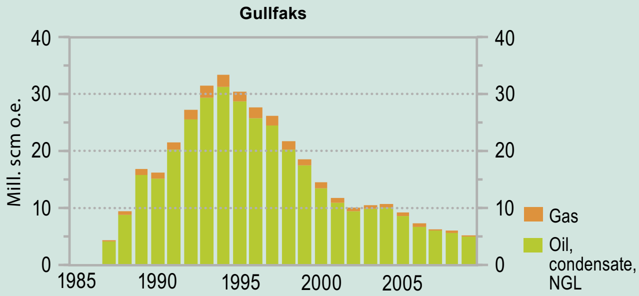
Gullfaks

Blocks and production licences	Block 34/10 - production licence 050, awarded 1978 Block 34/10 - production licence 050 B, awarded 1995	
Discovered	1978	
Development approval	09.10.1981 by the Storting	
On stream	22.12.1986	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS Statoil Petroleum AS	30.00 % 70.00 %
Recoverable reserves	**Original:** 361.5 million scm oil 22.7 billion scm gas 2.9 million tonnes NGL	**Remaining as of 31.12.2009** 16.8 million scm oil 0.1 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 72 000 barrels/day, NGL: 0.06 million tonnes	
Investment	Total investment is expected to be NOK 166.1 billion (2010 values) NOK 144.8 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

Development:
Gullfaks is an oil field located in the Tampen area in the northern part of the North Sea. The sea depth in the area is 130 – 220 metres. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides (Gullfaks A, B and C). Gullfaks B has a simplified processing plant with only first stage separation. Gullfaks A and C receive and process oil and gas from Gullfaks Sør and Gimle. The facilities are also involved in production and transport from Tordis, Vigdis and Visund. The Tordis production is processed in a separate facility on Gullfaks C. The original PDO for the Gullfaks field included the Gullfaks A and Gullfaks B facilities. A PDO for the eastern section (Gullfaks C) was approved on 01.06.1985. The PDO for Gullfaks Vest was approved on 15.01.1993, and recovery from the Lunde Formation was approved on 03.11.1995. In December 2005, an amended PDO for the Gullfaks field was approved. This plan covers prospects and small discoveries in the area around Gullfaks which can be drilled and produced from existing facilities.

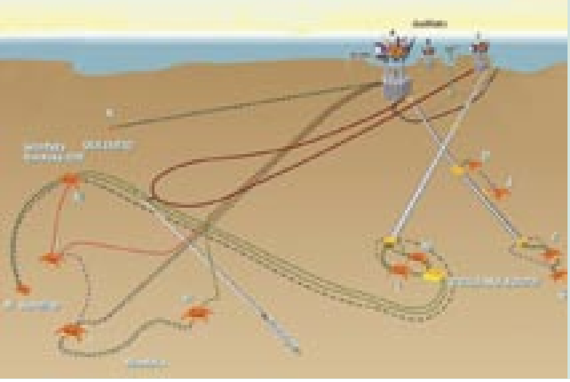
Reservoir:
The Gullfaks reservoirs consist of Middle Jurassic sandstones of the Brent Group, and Lower Jurassic and Upper Triassic sandstones of the Cook, Statfjord and Lunde Formations. The reservoirs lie 1 700 – 2 000 metres below the sea level. The Gullfaks reservoirs are located in rotated fault blocks in west and a structural horst in east, with a highly faulted area in-between.

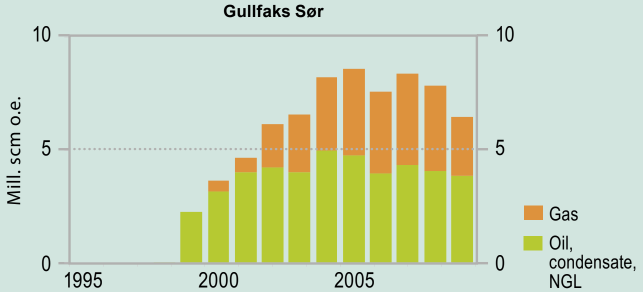
Recovery strategy:
The drive mechanisms are water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the drainage areas in the field, but water injection constitutes the main strategy.



Transport:
Oil is exported from Gullfaks A and Gullfaks C via loading buoys to shuttle tankers. The part of the rich gas that is not re-injected is sent through the export pipeline to Statpipe for further processing at Kårstø and export to the Continent as dry gas.

Status:
Production from Gullfaks is in tail production phase. Continuous efforts are being made to increase recovery, partly by locating and draining pockets of remaining oil in water-flooded areas, and partly through continued massive water injection. Implementation of a chemical flooding pilot is planned in 2010. A new project has also been initiated to evaluate necessary upgrades for the drilling facilities at Gullfaks A, B and C.





Gullfaks Sør

Blocks and production licences	Block 32/12 - production licence 152, awarded 1988	
	Block 33/12 - production licence 037 B, awarded 1998	
	Block 33/12 - production licence 037 E, awarded 2004	
	Block 34/10 - production licence 050, awarded 1978	
	Block 34/10 - production licence 050 B, awarded 1995	
Discovered	1978	
Development approval	29.03.1996 by the King in Council	
On stream	10.10.1998	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	30.00 %
	Statoil Petroleum AS	70.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	51.3 million scm oil	14.6 million scm oil
	61.5 billion scm gas	34.9 billion scm gas
	7.5 million tonnes NGL	4.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 41 000 barrels/day, Gas: 3.0 billion scm, NGL: 0.35 million tonnes	
Investment	Total investment is expected to be NOK 43.8 billion (2010 values)	
	NOK 38.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

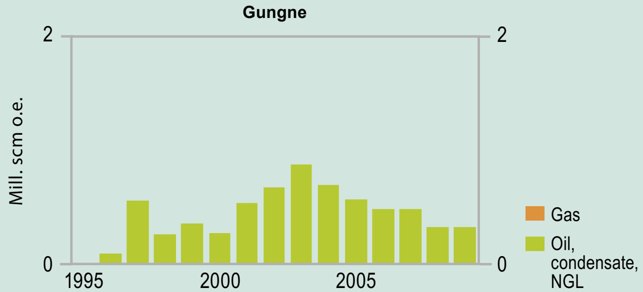
Development:
Gullfaks Sør is located to the south of Gullfaks in the northern part of the North Sea. It has been developed with a total of 12 subsea templates tied back to the Gullfaks A and Gullfaks C facilities. Gullfaks Sør has been developed in two phases. The PDO for Phase 1 included production of oil and condensate from the 34/10-2 Gullfaks Sør, 34/10-17 Rimfaks and 34/10-37 Gullveig deposits. The PDO for Phase 2 was approved on 08.06.1998 and covered production of gas from the Brent Group in the Gullfaks Sør deposit. In 2004 the 34/10-47 Gulltopp discovery was included in Gullfaks Sør. Gulltopp is produced through an extended reach production well from Gullfaks A. A PDO for Rimfaks IOR and the 33/12-8 A Skinfaks discovery was approved on 11.02.2005. This project includes a new subsea template and a satellite well. Skinfaks is now included in Gullfaks Sør and production started in January 2007.

Reservoir:
The Gullfaks Sør reservoirs consist of Middle Jurassic sandstones of the Brent Group and Lower Jurassic and Upper Triassic sandstones of the Cook, Statfjord and Lunde Formations. The Brent and Statfjord reservoirs are producing. The reservoirs lie 2 400 - 3 400 metres below the sea level, in rotated fault blocks. The reservoirs in the Gullfaks Sør deposit are heavily segmented, with many internal faults, and the Statfjord Formation has poor flow characteristics. The other deposits, however, show good reservoir qualities.

Recovery strategy:
Recovery from Gullfaks Sør is driven by pressure depletion after gas injection ceased in 2009. The Brent reservoir in Rimfaks is produced by full pressure maintenance by gas injection, whereas the Statfjord Formation has partial pressure support from gas injection. The deposits Gullveig and Gulltopp are recovered by pressure depletion and natural aquifer drive. Production here is also affected by the production from Gullfaks.

Transport:
The oil is transported to Gullfaks A for processing, storage and further transport by tankers. Rich gas is processed on Gullfaks C and then exported through Statpipe to Kårstø for further processing and export to the Continent as dry gas.

Status:
Production from the Statfjord Formation in Gullfaks Sør has ceased due to low reservoir pressure. A gas injection well is planned in order to resume production. The production from Skinfaks is also down due to low reservoir pressure. Gas lift will be installed on Skinfaks from the summer 2010 and in the well on Gulltopp late in 2010.



Gungne

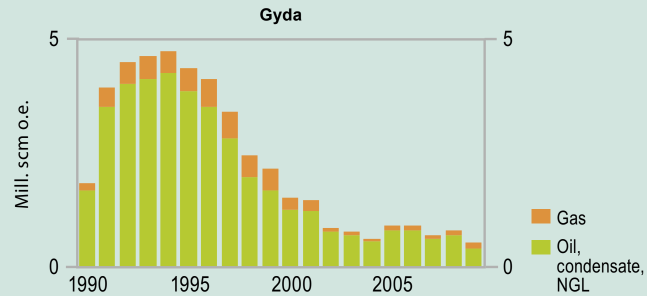
Blocks and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1982	
Development approval	29.08.1995 by the King in Council	
On stream	21.04.1996	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	28.00 %
	Statoil Petroleum AS	62.00 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	15.0 billion scm gas	2.2 billion scm gas
	2.0 million tonnes NGL	0.3 million tonnes NGL
	4.6 million scm condensate	0.5 million scm condensate
Production	**Estimated production in 2010:**	
	Gas: 0.51 billion scm, NGL: 0.06 million tonnes, Condensate: 0.1 million scm	
Investment	Total investment is expected to be NOK 2.5 billion (2010 values)	
	NOK 2.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Gungne is a small gas condensate field located in the Sleipner area in the middle part of the North Sea. The sea depth in the area is 83 metres. Gungne produces via three wells drilled from Sleipner A.

Reservoir:
The reservoir consists of sandstones of the Skagerrak Formation of Triassic age. The reservoir depth is about 2 800 metres. The reservoir quality is generally good, but the reservoir is segmented, and lateral shale layers act as internal barriers.

Recovery strategy:
Gungne is recovered by pressure depletion.

Transport:
Gas and condensate from Sleipner Øst and Gungne are processed on Sleipner A. Processed gas from Sleipner A is mixed with gas from Troll and exported in Zeepipe to Zeebrugge.



Gyda

Blocks and production licences	Block 2/1 - production licence 019 B, awarded 1977	
Discovered	1980	
Development approval	02.06.1987 by the Storting	
On stream	21.06.1990	
Operator	Talisman Energy Norge AS	
Licensees	DONG E&P Norge AS	34.00 %
	Norske AEDC A/S	5.00 %
	Talisman Energy Norge AS	61.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	39.6 million scm oil	4.5 million scm oil
	7.0 billion scm gas	1.0 billion scm gas
	2.0 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 8 000 barrels/day, Gas: 0.11 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 21.9 billion (2010 values)	
	NOK 20.0 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

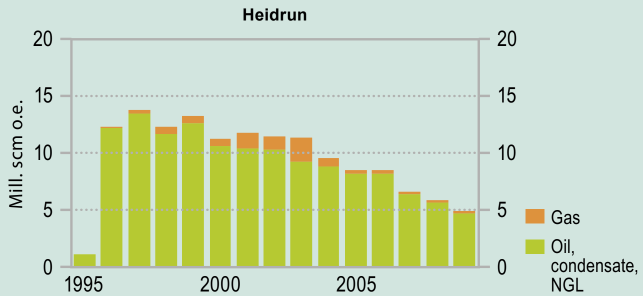
Development:
Gyda is an oil field located between Ula and Ekofisk in the southern part of the North Sea. The sea depth in the area is 66 metres. The field has been developed with a combined drilling, accommodation and processing facility with a steel jacket.

Reservoir:
Gyda consists of three reservoir areas in Upper Jurassic sandstones of the Ula Formation. The reservoir depth is about 4 000 metres.

Recovery strategy:
The field produces with water injection as the drive mechanism for the main part of the field. Pressure support from the gas cap and the aquifer are drive mechanisms for other parts of the field.

Transport:
The oil is transported to Ekofisk via the oil pipeline from Ula and further in Norpipe to Teesside. The gas is transported in a dedicated pipeline to Ekofisk for onward transport in Norpipe to Emden.

Status:
Gyda is in its tail phase and experiences increasing water production and challenges in maintaining the oil production. The production licence period has been extended to 2018 and work is ongoing to prolong the lifetime of the field correspondingly. A new onshore operations room was opened in 2009 to optimise production. Gas lift has increased well production, and the gas lift capacity will be extended. Improved recovery by means of gas injection is being considered.



Heidrun

Blocks and production licences	Block 6507/8 - production licence 124, awarded 1986	
	Block 6707/7 - production licence 095, awarded 1984	
Discovered	1985	
Development approval	14.05.1991 by the Storting	
On stream	18.10.1995	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	24.31 %
	Eni Norge AS	5.12 %
	Petoro AS	58.16 %
	Statoil Petroleum AS	12.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	170.0 million scm oil	38.1 million scm oil
	42.6 billion scm gas	29.9 billion scm gas
	2.2 million tonnes NGL	1.7 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 64 000 barrels/day, Gas: 0.29 billion scm, NGL: 0.03 million tonnes	
Investment	Total investment is expected to be NOK 98.5 billion (2010 values)	
	NOK 79.7 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

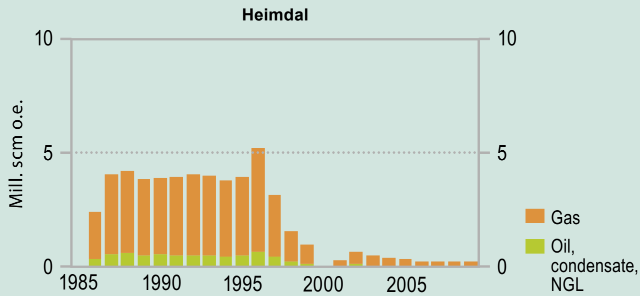
Development:
The Heidrun field is located on Haltenbanken in the Norwegian Sea. The sea depth in the area is 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with subsea facilities. The PDO for the Heidrun north flank was approved on 12.05.2000.

Reservoir:
The reservoir consists of sandstones of the Garn, Ile, Tilje and Åre Formations of Early and Middle Jurassic age. The reservoir is heavily faulted. The Garn and Ile Formations have good reservoir quality, while the Tilje and Åre Formations are more complex. The reservoir depth is about 2 300 metres.

Recovery strategy:
The recovery strategy for the field is pressure maintenance using water and gas injection in the Garn and Ile Formations. In the more complex part of the reservoir, in the Tilje and Åre Formations, the main recovery strategy is water injection. Some segments are also produced by pressure depletion.

Transport:
The oil is transferred to tankers at the field and shipped to Mongstad and Tetney (UK). The gas is transported in a pipeline to Tjeldbergodden and in Åsgard Transport to Kårstø.

Status:
Reserve estimates for Heidrun were reduced in 2009, based on a new reservoir model and fewer wells drilled than planned. New well targets are continuously being considered in an effort to increase oil recovery. An extension of the gas treatment capacity and different pilots to improve recovery are being considered.



Heimdal

Blocks and production licences	Block 25/4 - production licence 036 BS, awarded 2003	
Discovered	1972	
Development approval	10.06.1981 by the Storting	
On stream	13.12.1985	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	23.80 %
	Petoro AS	20.00 %
	Statoil Petroleum AS	39.44 %
	Total E&P Norge AS	16.76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	7.2 million scm oil	0.7 million scm oil
	44.8 billion scm gas	0.4 billion scm gas
Production	**Estimated production in 2010:**	
	Gas: 0.15 billion scm	
Investment	Total investment is expected to be NOK 25.1 billion (2010 values)	
	NOK 25.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

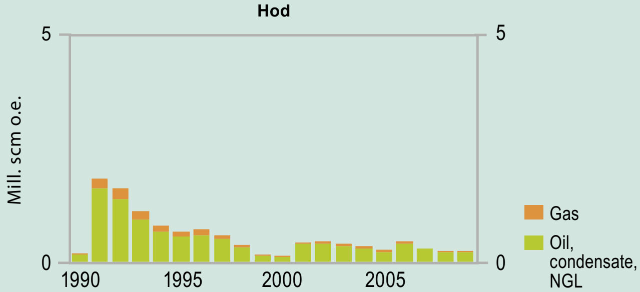
Development:
Heimdal is a gas field located in the middle part of the North Sea. The sea depth in the area is 120 metres. The field has been developed with an integrated drilling, production and accommodation facility with a steel jacket (HMP1). The Heimdal Jurassic development was approved on 02.10.1992. PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999. This included a new riser facility (HRP), connected by a bridge to HMP1. Heimdal is now mainly a processing centre for other fields. Huldra, Skirne and Vale deliver gas to Heimdal, and in addition, gas from Oseberg is transported via Heimdal.

Reservoir:
The reservoir consists of sandstones of the Heimdal Formation of Paleocene age, deposited as sub-marine fan systems. The reservoir depth is about 2 100 metres.

Recovery strategy:
The field has been recovered by pressure depletion and has now more or less ceased producing.

Transport:
Originally, gas from Heimdal was sent in Statpipe to Kårstø and on to the Continent, but can now also be sent in Vesterled to St. Fergus in the United Kingdom. After Heimdal Gas centre was established, a new gas pipeline was connected to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has also been laid from Heimdal to Grane for gas injection. Condensate is transported by pipeline to Brae in the British sector.

Status:
The licensees are searching for new gas resources that can be tied to Heimdal to prolong the lifetime of the gas centre.



Hod

Blocks and production licences	Block 2/11 - production licence 033, awarded 1969	
Discovered	1974	
Development approval	26.06.1988 by the Storting	
On stream	30.09.1990	
Operator	BP Norge AS	
Licensees	BP Norge AS	25.00 %
	Enterprise Oil Norge AS	25.00 %
	Hess Norge AS	25.00 %
	Total E&P Norge AS	25.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	9.8 million scm oil	0.6 million scm oil
	1.7 billion scm gas	0.1 billion scm gas
	0.4 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 3 000 barrels/day, Gas: 0.02 billion scm	
Investment	Total investment is expected to be NOK 4.0 billion (2010 values)	
	NOK 3.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

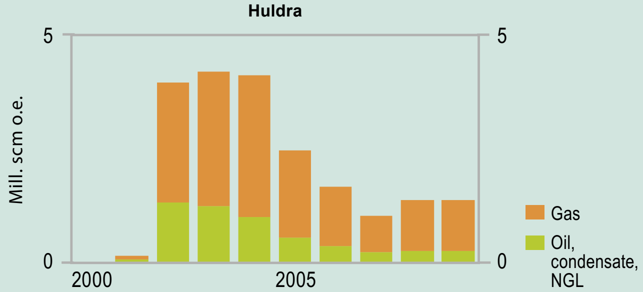
Development:
Hod is an oil field located 13 kilometres south of the Valhall field in the southern part of the North Sea. The sea depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. In addition, the field produces through wells drilled from Valhall. The PDO for the Hod Sadel area was approved on 20.06.1994.

Reservoir:
The reservoir consists of chalk in the Ekofisk, Tor and Hod Formations of Early Paleocene and Late Cretaceous age. The reservoir depth is approximately 2 700 metres. The field consists of the three structures Hod Vest, Hod Øst and Hod Sadel. Hod Sadel connects Hod to Valhall and is producing through four wells drilled from Valhall.

Recovery strategy:
Recovery takes place through pressure depletion. Gas lift is used in two wells to increase production. There are plans to start a water injection pilot at Hod in 2010.

Transport:
Oil and gas are transported in a shared pipeline to Valhall for further processing. The transport systems to Teesside and Emden are used for onward transport.

Status:
Production from Hod Øst and Hod Vest is stable at a low level. The field is in a late phase with the current recovery strategy. In 2010 a water injection pilot for one well will be started. It is expected that the licensees in 2010 will apply for an extension of the production licence beyond 2015.



Huldra

Blocks and production licences	Block 30/2 - production licence 051, awarded 1979	
	Block 30/3 - production licence 052 B, awarded 2001	
Discovered	1982	
Development approval	02.02.1999 by the Storting	
On stream	21.11.2001	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	23.34 %
	Petoro AS	31.96 %
	Statoil Petroleum AS	19.88 %
	Talisman Resources Norge AS	0.50 %
	Total E&P Norge AS	24.33 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	4.9 million scm oil	0.1 million scm oil
	16.0 billion scm gas	1.1 billion scm gas
	0.1 million tonnes NGL	
Production	**Estimated production in 2010:**	
	Oil: 2 000 barrels/day, Gas: 0.54 billion scm	
Investment	Total investment is expected to be NOK 10.5 billion (2010 values)	
	NOK 10.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

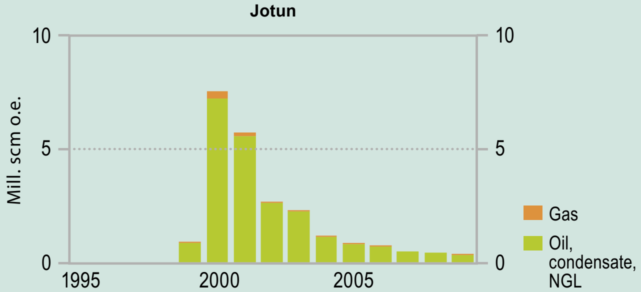
Development:
Huldra is a gas condensate field located north of Oseberg in the northern part of the North Sea. The sea depth in the area is 125 metres. The field is developed with a steel wellhead facility with a simple process plant. The facility is remotely operated from Veslefrikk B, 16 kilometres away.

Reservoir:
The reservoir is in Middle Jurassic sandstones of the Brent Group in a rotated fault block. The reservoir has high pressure and high temperature and lies at a depth of 3 500 – 3 900 metres. There are many small faults in the field, and reservoir communication is uncertain, but the production history indicates two main segments without pressure communication.

Recovery strategy:
Huldra is recovered by pressure depletion. Low pressure production began in 2007 after a gas compressor was installed on the field. The compressor will prolong the lifetime of the field by five years.

Transport:
Following first stage separation, the wet gas is transported to Heimdal for further processing, whereas the condensate is transported to Veslefrikk for processing.

Status:
Huldra is in the tail production phase and it is expected that the field will cease production in 2014.



Jotun

Blocks and production licences	Block 25/7 - production licence 103 B, awarded 1998 Block 25/8 - production licence 027 B, awarded 1999	
Discovered	1994	
Development approval	10.06.1997 by the Storting	
On stream	25.10.1999	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	Dana Petroleum Norway AS	45.00 %
	Det norske oljeselskap ASA	7.00 %
	ExxonMobil Exploration & Production Norway AS	45.00 %
	Petoro AS	3.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	23.4 million scm oil	1.3 million scm oil
	0.9 billion scm gas	0.1 billion scm gas
Production	**Estimated production in 2010:**	
	Oil: 5 000 barrels/day, Gas: 0.01billion scm	
Investment	Total investment is expected to be NOK 14.4 billion (2010 values) NOK 14.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

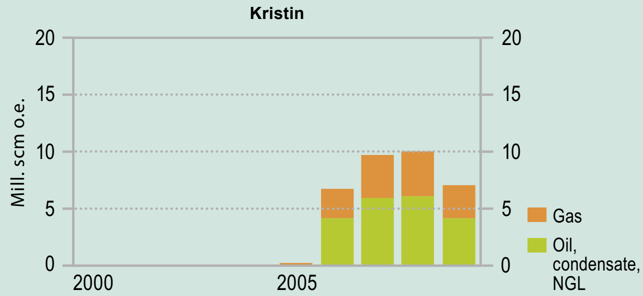
Development:
Jotun is an oil field located 25 kilometres north of Balder in the middle part of the North Sea. The sea depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel (FPSO), Jotun A, and a wellhead facility, Jotun B. Jotun is integrated with Balder and processes gas from Balder and oil from the Jurassic reservoir in the Ringhorne deposit.

Reservoir:
The Jotun field comprises three structures and the easternmost structure has a small gas cap. The reservoirs consist of sandstones of the Heimdal Formation of Paleocene age. The reservoirs are deposited in a sub-marine fan system and lie at a depth of about 2 000 metres. To the west the sand has good reservoir quality, while the shale content increases towards the east.

Recovery strategy:
The field is recovered by pressure support from the aquifer. Produced water is now injected in the Utsira Formation, and is no longer used for pressure support. Gas lift is used in all the wells.

Transport:
The oil is exported via the production vessel to tankers. The processed rich gas is exported via Statpipe to Kårstø.

Status:
The field is in the tail production phase, with expected production until 2015. Water cut continues to rise, and now more than 90 per cent of the wellstream is water.



Kristin

Blocks and production licences	Block 6406/2 - production licence 199, awarded 1993 Block 6506/11 - production licence 134 B, awarded 2000	
Discovered	1997	
Development approval	17.12.2001 by the Storting	
On stream	03.11.2005	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	8.25 %
	ExxonMobil Exploration & Production Norway AS	10.88 %
	Petoro AS	19.58 %
	Statoil Petroleum AS	55.30 %
	Total E&P Norge AS	6.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	23.9 million scm oil	11.3 million scm oil
	25.9 billion scm gas	12.6 billion scm gas
	5.8 million tonnes NGL	3.0 million tonnes NGL
	2.1 million scm condensate	
Production	**Estimated production in 2010:** Oil: 40 000 barrels/day, Gas: 2.39 billion scm, NGL: 0.53 million tonnes	
Investment	Total investment is expected to be NOK 31.9 billion (2010 values) NOK 30.5 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

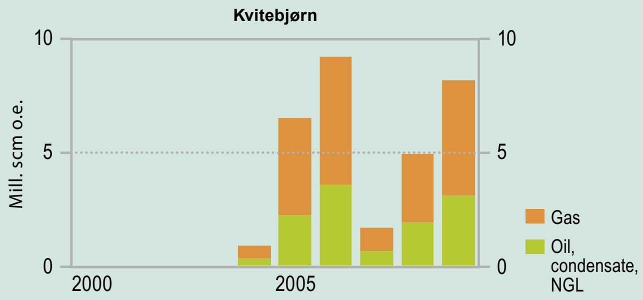
Development:
Kristin is a gas condensate field in the Norwegian Sea. The field is developed with four subsea templates tied back to a semi-submersible facility for processing, Kristin Semi. The sea depth in the area is about 370 metres. Provision has been made for tie-in and processing of other deposits in the Kristin area. Tyrihans is tied back to Kristin and started production in 2009.

Reservoir:
The reservoirs are in Jurassic sandstones of the Garn, Ile and Tofte Formations and contain gas and condensate under very high pressure and temperatures. The reservoirs lie at a depth of 4 600 metres. The reservoir quality is good, but low permeability in the Garn Formation and flow barriers in the Ile and Tofte Formations contribute to a rapid decline in reservoir pressure during production.

Recovery strategy:
Kristin is recovered by pressure depletion.

Transport:
The wellstream is processed at Kristin and the gas is transported in a pipeline to Åsgard Transport and further to Kårstø. Light oil is transferred to Åsgard for storage and export. Condensate from Kristin is sold as oil (Halten Blend).

Status:
The reservoir pressure at Kristin is decreasing faster than expected, leading to challenges such as production of water and sand. Work is ongoing to find technical solutions to production and drilling challenges related to pressure decrease and water breakthrough in wells. Low pressure production from the reservoir is being planned. This will contribute to improved recovery. Work is being done on the development of additional resources in nearby segments. Kristin is also evaluated as a possible processing centre for other discoveries in the area.



Kvitebjørn

Blocks and production licences	Block 34/11 - production licence 193, awarded 1993	
Discovered	1994	
Development approval	14.06.2000 by the Storting	
On stream	26.09.2004	
Operator	Statoil Petroleum AS	
Licensees	Enterprise Oil Norge AS	6.45 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	58.55 %
	Total E&P Norge AS	5.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	25.3 million scm oil	15.6 million scm oil
	75.0 billion scm gas	55.3 billion scm gas
	4.0 million tonnes NGL	2.3 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 49 000 barrels/day, Gas: 6.58 billion scm, NGL: 0.31 million tonnes	
Investment	Total investment is expected to be NOK 20.4 billion (2010 values)	
	NOK 15.6 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Florø	

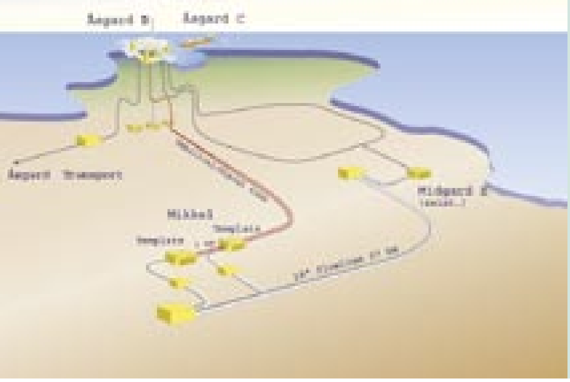
Development:
Kvitebjørn is a gas condensate field located in the eastern part of the Tampen area, in the northern part of the North Sea. Sea depth in the area is about 190 metres. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. Drill cuttings and produced water are injected in a dedicated disposal well. Amended PDO for Kvitebjørn was approved in December 2006.

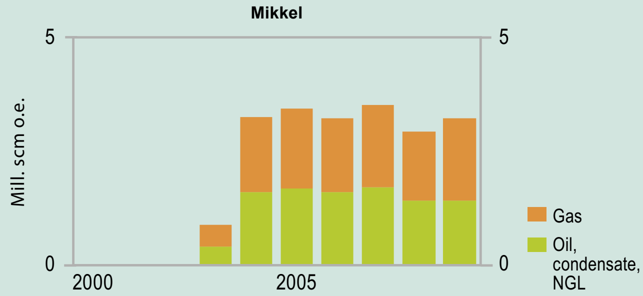
Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir lies at approximately 4 000 metres depth, and has high temperature and high pressure. The reservoir quality is good.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
Rich gas is transported in a dedicated pipeline to Kollsnes, while condensate is transported in a pipeline tied to the Troll Oil Pipeline II for onward transport to Mongstad.

Status:
There are plans to install a compressor on the field. This will increase recovery because the reservoir pressure can be further reduced. A decision regarding pre-compression is expected in 2010. A new well has proven additional resources on the field.





Mikkel

Blocks and production licences	Block 6407/5 - production licence 121, awarded 1986	
	Block 6407/6 - production licence 092, awarded 1984	
Discovered	1987	
Development approval	14.09.2001 by the King in Council	
On stream	01.08.2003	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	14.90 %
	ExxonMobil Exploration & Production Norway AS	33.48 %
	Statoil Petroleum AS	43.97 %
	Total E&P Norge AS	7.65 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	4.6 million scm oil	2.6 million scm oil
	22.8 billion scm gas	12.2 billion scm gas
	6.3 million tonnes NGL	3.4 million tonnes NGL
	2.3 million scm condensate	
Production	**Estimated production in 2010:**	
	Oil: 8 000 barrels/day, Gas: 1.65 billion scm, NGL: 0.44 million tonnes	
Investment	Total investment is expected to be NOK 2.6 billion (2010 values)	
	NOK 2.5 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

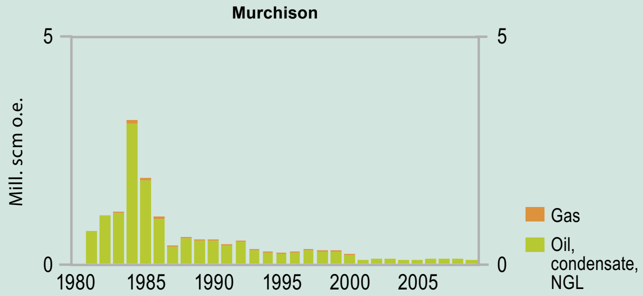
Development:
Mikkel is a gas condensate field located in the eastern part of the Norwegian Sea, about 30 kilometres north of Draugen. The sea depth in the area is 220 metres. The field has been developed with two subsea templates tied back to Åsgard B.

Reservoir:
The field has a 300 metres thick gas condensate column and a thin underlying oil zone. The reservoir consists of Jurassic sandstones in the Garn, Ile and Tofte Formations in six structures separated by faults, all with good reservoir quality. The reservoir depth is approximately 2 500 metres.

Recovery strategy:
Mikkel is recovered by pressure depletion.

Transport:
The wellstream from Mikkel is combined with the wellstream from the Midgard deposit and routed to Åsgard B for processing. The condensate is separated from the gas and stabilised before it is shipped together with condensate from Åsgard. The condensate is sold as oil (Halten Blend). The rich gas is sent by the Åsgard Transport pipeline to Kårstø for separation of NGL. The dry gas is transported on from Kårstø to the Continent by the Europipe II pipeline.

Status:
Compressor capacity (subsea or floating) is planned to be installed to maintain pressure in the pipeline from Mikkel.



Murchison

Blocks and production licences	Block 33/9 - production licence 037 C, awarded 2000 The Norwegian part of the field is 22.2%, the British part is 77.8%	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees	Wintershall Norge ASA CNR International (UK) Limited	22.20 % 77.80 %
Recoverable reserves (Norwegian part)	**Original:** 14.3 million scm oil 0.4 billion scm gas	**Remaining as of 31.12.2009** 0.6 million scm oil 0.1 billion scm gas
Production	**Estimated production in 2010:** Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 9.5 billion (2010 values) NOK 9.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Aberdeen, Scotland	
Main supply base	Peterhead, Scotland	

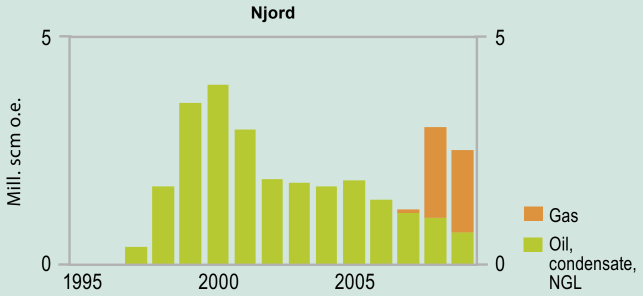
Development:
Murchison straddles the border between the Norwegian and British sectors in the Tampen area, in the northern part of the North Sea. The field has been developed with a combined drilling, accommodation and production facility with a steel jacket situated in the British sector. The British and Norwegian licensees entered into an agreement in 1979 concerning common exploitation of the resources in the Murchison field. The agreement also involves British and Norwegian authorities.

Reservoir:
The reservoirs are in Jurassic sandstones.

Recovery strategy:
The field is recovered by pressure support from water injection.

Transport:
The production is sent through the Brent system to Sullom Voe in the Shetlands.

Status:
Murchison is in tail production, but it is anticipated that the field will produce until 2019.



Njord

Blocks and production licences	Block 6407/10 - production licence 132, awarded 1987	
	Block 6407/7 - production licence 107, awarded 1985	
Discovered	1986	
Development approval	12.06.1995 by the Storting	
On stream	30.09.1997	
Operator	Statoil Petroleum AS	
Licensees	E.ON Ruhrgas Norge AS	30.00 %
	ExxonMobil Exploration & Production Norway AS	20.00 %
	GDF SUEZ E&P Norge AS	20.00 %
	Petoro AS	7.50 %
	Statoil Petroleum AS	20.00 %
	VNG Norge AS	2.50 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	26.1 million scm oil	2.4 million scm oil
	10.4 billion scm gas	6.5 billion scm gas
	2.1 million tonnes NGL	2.1 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 11 000 barrels/day, Gas: 1.79 billion scm, NGL: 0.36 million tonnes	
Investment	Total investment is expected to be NOK 20.9 billion (2010 values)	
	NOK 18.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

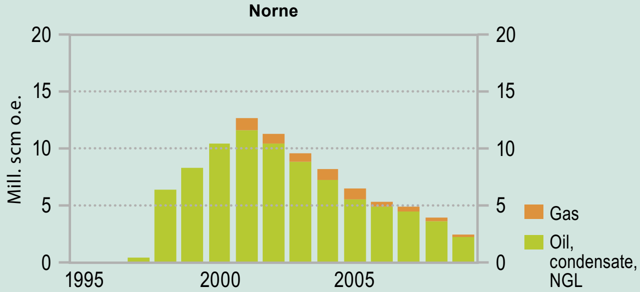
Development:
Njord is an oil field located about 30 kilometres west of Draugen in the Norwegian Sea. The sea depth in the area is 330 metres. The field has been developed with a semi-submersible drilling, accommodation and production facility and a storage vessel, Njord B. The facility is located over subsea completed wells connected through flexible risers. The PDO for Njord gas export was approved on 21.01.2005. At the beginning of 2010, the authorities consented to PDO exemption regarding development of the northwest flank.

Reservoir:
The reservoir consists of Jurassic sandstones of the Tilje and Ile Formations. The field has a complicated fault pattern with only partial communication between the segments. The reservoir depth is approximately 2 850 metres.

Recovery strategy:
Initial production strategy was gas injection for pressure support in parts of the reservoir and pressure depletion in the rest of the reservoir. After gas export started in 2007, only minor volumes of gas are injected. Due to the complex reservoir with many faults, the field has a relatively low recovery factor.

Transport:
The oil is off-loaded from the storage vessel to tankers for transport to the market. The gas is transported through Åsgard Transport to Kårstø.

Status:
Njord is in the tail production phase, and new wells are being drilled to maintain production. Three new wells will be drilled during 2010/2011. The northwest flank will be drilled and produced from the Njord facility with expected production start in 2012.



Norne

Blocks and production licences	Block 6508/1 - production licence 128 B, awarded 1998	
	Block 6608/10 - production licence 128, awarded 1986	
Discovered	1992	
Development approval	09.03.1995 by the Storting	
On stream	06.11.1997	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	6.90 %
	Petoro AS	54.00 %
	Statoil Petroleum AS	39.10 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	94.7 million scm oil	12.0 million scm oil
	10.5 billion scm gas	4.5 billion scm gas
	1.6 million tonnes NGL	0.9 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 35 000 barrels/day, Gas: 0.14 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 38.1 billion (2010 values)	
	NOK 30.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

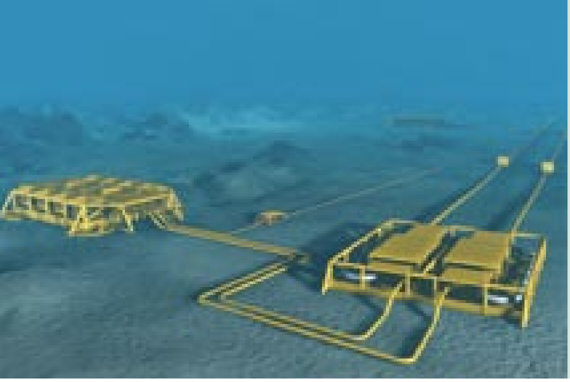
Development:
Norne is an oil field located about 80 kilometres north of the Heidrun field in the Norwegian Sea. The sea depth in the area is 380 metres. The field has been developed with a production and storage vessel, "Norne FPSO", connected to seven subsea templates. Flexible risers carry the wellstream up to the production vessel. In April 2008, an amended PDO for Norne and Urd was approved. The plan encompasses 6608/10-11 S Trost and several prospects in the area around Norne and Urd.

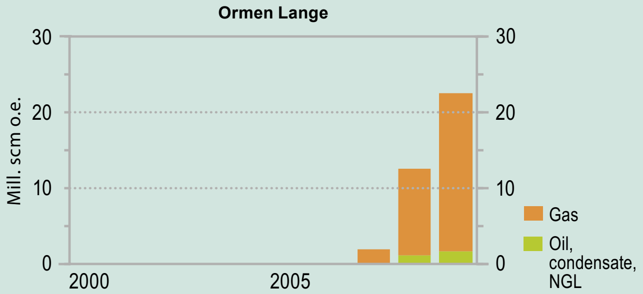
Reservoir:
The reservoir is in Jurassic sandstones. Oil is mainly found in the Ile and Tofte Formations, and gas in the Not Formation. The reservoir depth is about 2 500 metres. The reservoir quality is good.

Recovery strategy:
The oil is produced by water injection as drive mechanism. Gas injection ceased in 2005 and all gas is now being exported.

Transport:
The oil is loaded to tankers for export. Gas export started in 2001, and the gas is transported through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Various measures to improve recovery are being considered, including use of new well technology. A new subsea template (M-template) is installed in the southern part of the field and the first well from this template will be drilled in 2010.





Ormen Lange

Blocks and production licences	Block 6305/4 - production licence 209, awarded 1996 Block 6305/5 - production licence 209, awarded 1996 Block 6305/7 - production licence 208, awarded 1996 Block 6305/8 - production licence 250, awarded 1999	
Discovered	1997	
Development approval	02.04.2004 by the Storting	
On stream	13.09.2007	
Operator	A/S Norske Shell	
Licensees	A/S Norske Shell DONG E&P Norge AS ExxonMobil Exploration & Production Norway AS Petoro AS Statoil Petroleum AS	17.04 % 10.34 % 7.23 % 36.48 % 28.92 %
Recoverable reserves	**Original:** 301.7 billion scm gas 18.6 million scm condensate	**Remaining as of 31.12.2009** 267.8 billion scm gas 15.8 million scm condensate
Production	**Estimated production in 2010:** Gas: 22.39 billion scm, Condensate: 1.69 million tonnes	
Investment*	Total investment is expected to be NOK 72.1 billion (2010 values) NOK 30.5 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Kristiansund	

** Total investment, including land facilities is expected to be 101.2 billion (2010 values)*

Development:
Ormen Lange is a gas field located in the Møre Basin in the southern part of the Norwegian Sea. The sea depth in the area varies from 800 - 1 100 metres. The deep water has made the development very challenging and has triggered development of new technology. The field is being developed in several phases with 24 wells from three subsea templates.

Reservoir:
The main reservoir consists of sandstones of Paleocene age in the "Egga" Formation, about 2 700 - 2 900 metres below sea level.

Recovery strategy:
The field is recovered by pressure depletion and, at a later stage, gas compression.

Transport:
The wellstream, which contains gas and condensate, is transported in two multi-phase pipelines to the onshore facility at Nyhamna, where gas is dried and compressed before it is sent in the gas export pipeline, Langeled, via Sleipner R to Great Britain.

Status:
The field is producing at plateau with 10 wells. A third subsea template was installed in the southern part of the field in 2009 and will start producing with three wells in 2010. Disappointing well results from the northern part of the field have contributed to lower reserve estimates. Future gas compression solutions for the field are being evaluated.

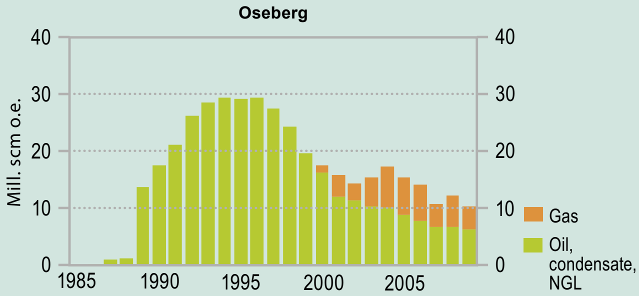

Oseberg

Blocks and production licences	Block 30/6 - production licence 053, awarded 1979 Block 30/9 - production licence 079, awarded 1982	
Discovered	1979	
Development approval	05.06.1984 by the Storting	
On stream	01.12.1988	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	Statoil Petroleum AS	49.30 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	374.8 million scm oil	24.4 million scm oil
	105.7 billion scm gas	81.5 billion scm gas
	10.5 million tonnes NGL	4.2 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 74 000 barrels/day, Gas: 2.77 billion scm, NGL: 0.55 million tonnes	
Investment	Total investment is expected to be NOK 130.9 billion (2010 values) NOK 112.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Oseberg is an oil field with a gas cap. The field is located in the northern part of the North Sea. The sea depth in the area is about 100 metres. Oseberg is developed in multiple phases. The Oseberg Field Centre in the south consists of two facilities, the process and accommodation facility Oseberg A and the drilling and water injection facility Oseberg B. Oseberg C is an integrated production, drilling and accommodation facility (PDQ) in the northern part of the field. Oseberg D is a facility for gas processing tied to the Oseberg Field Centre. Oseberg Vestflanke has been developed with a subsea template tied back to Oseberg B. Oseberg Delta will be developed with a subsea template tied back to Oseberg D. Production from the Gamma Main structure started in 2008 with two wells from the Oseberg Field Centre. The facilities at the Field Centre process oil and gas from the fields Oseberg Øst, Oseberg Sør and Tune. The PDO for the northern part of the field was approved on 19.01.1988. The PDO for Oseberg D was approved on 13.12.1996. The PDO for Oseberg Vestflanke was approved on 19.12.2003, and the PDO for Oseberg Delta was approved on 23.09.2005.

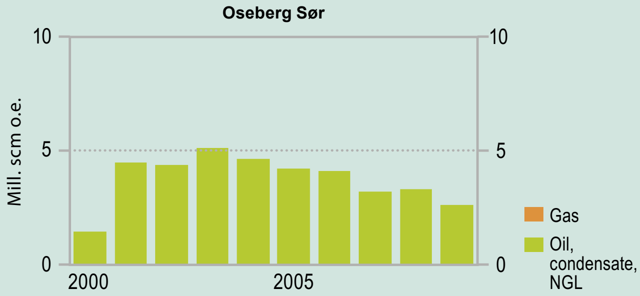
Reservoir:
The field consists of several Middle Jurassic sandstone reservoirs of the Brent Group, and is divided into several structures. The main reservoirs are in the Oseberg and Tarbert Formations, but production also takes place from the Etive and Ness Formations. The reservoirs lie at a depth of 2 300 - 2 700 metres and generally have good reservoir characteristics.

Recovery strategy:
The Oseberg field produces by pressure maintenance with the injection of both gas and water, and by water alternating gas injection (WAG). Massive up-flank gas injection in the main field has provided excellent oil displacement, and a large gas cap has now developed which will be recovered in the future. Injection gas was previously imported from Troll Øst (TOGI) and Oseberg Vest. Small parts of the field produce by pressure depletion.



Transport:
The oil is sent through the Oseberg Transport System (OTS) to the Sture terminal. Gas export began in 2000 through a pipeline, Oseberg Gas Transport (OGT), to the Statpipe system via the Heimdal facility.

Status:
The challenge on Oseberg will be to produce the remaining oil below the gas cap, and to balance the gas offtake with regard to oil recovery from the field. A postponed start of the gas blowdown has been decided by the licensees. A module for low pressure production has been installed at the Oseberg Field Centre and the compressor has been upgraded. Test production is ongoing from an overlying chalk reservoir in the Shetland Group on the Oseberg field to evaluate the flow characteristics. Studies for further recovery will be completed during 2010.



Oseberg Sør

Blocks and production licences	Block 30/12 - production licence 171 B, awarded 2000	
	Block 30/9 - production licence 079, awarded 1982	
	Block 30/9 - production licence 104, awarded 1985	
Discovered	1984	
Development approval	10.06.1997 by the Storting	
On stream	05.02.2000	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	Statoil Petroleum AS	49.30 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	52.7 million scm oil	15.5 million scm oil
	11.8 billion scm gas	5.9 billion scm gas
	1.5 million tonnes NGL	1.5 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 39 000 barrels/day, Gas: 0.37 billion scm, NGL: 0.09 million tonnes	
Investment	Total investment is expected to be NOK 29.3 billion (2010 values)	
	NOK 23.9 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

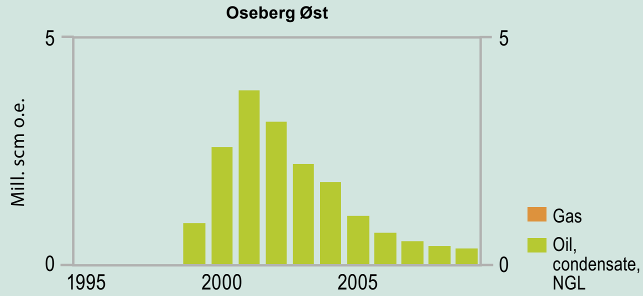
Development:
Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The sea depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first-stage separation of oil and gas. In addition, several deposits included in the Oseberg Sør field have been developed with subsea templates tied back to the Oseberg Sør facility. Final processing of oil and gas takes place on the Oseberg Field Centre. The development of the Oseberg Sør J structure was approved on 15.05.2003 and production started in November 2006.

Reservoir:
Oseberg Sør consists of several deposits with Jurassic sandstone reservoirs. The reservoir depth is between 2 200 - 2 800 metres. The main reservoirs are in the Tarbert and Heather Formations. The reservoir quality is moderate.

Recovery strategy:
Recovery mainly takes place by water and gas injection. In parts of the field water alternating gas injection (WAG) is being used. Water used for injection is produced from the Utsira Formation.

Transport:
The oil is transported from the Oseberg Sør facility by pipeline to the Oseberg Field Centre where it is processed and transported through Oseberg Transport System (OTS) to the Sture terminal. The gas is transported via Oseberg Gas Transport (OGT) to Statpipe.

Status:
The Oseberg Sør G Sentral deposit is being developed by wells drilled from the Oseberg Sør facility. Production is expected to start in May 2010. Several new wells will be drilled on Oseberg Sør in 2010.



Oseberg Øst

Blocks and production licences	Block 30/6 - production licence 053, awarded 1979	
Discovered	1981	
Development approval	11.10.1996 by the King in Council	
On stream	03.05.1999	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	2.40 %
	ExxonMobil Exploration & Production Norway AS	4.70 %
	Petoro AS	33.60 %
	Statoil Petroleum AS	49.30 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	28.6 million scm oil	11.1 million scm oil
	0.4 billion scm gas	0.1 billion scm gas
	0.1 million tonnes NGL	0.1 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 7 000 barrels/day	
Investment	Total investment is expected to be NOK 15.8 billion (2010 values)	
	NOK 11.5 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

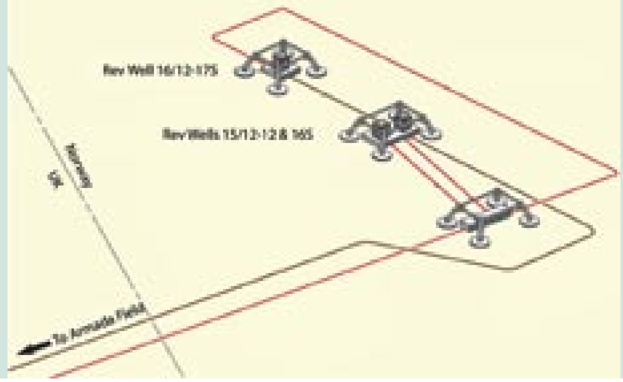
Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is about 160 metres.

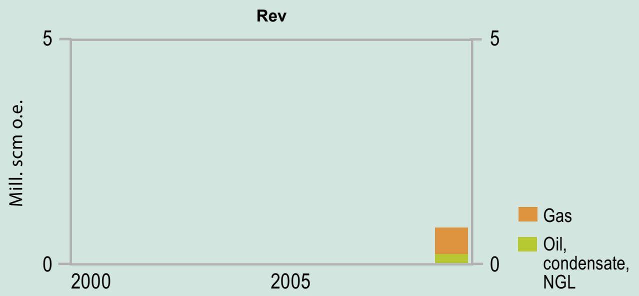
Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil bearing layers of Middle Jurassic sandstones in the Brent Group, with varying reservoir characteristics. The reservoir lies at a depth of 2 700 – 3 100 metres.

Recovery strategy:
The field is produced by partial pressure support from water injection and water alternating gas injection (WAG).

Transport:
The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sture terminal. The gas is mainly used for injection, gas lift and fuel.

Status:
The drilling equipment on the Oseberg Øst facility has been upgraded. One main challenge is to balance production with a limited availability of water and gas for injection.





Rev

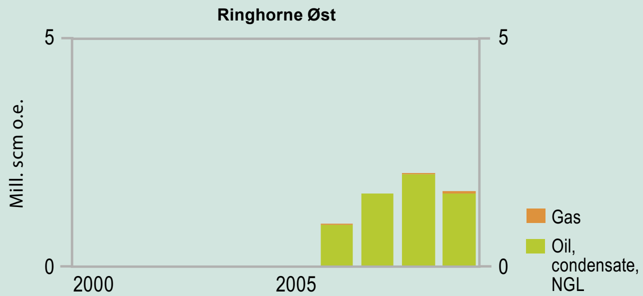
Blocks and production licences	Block 15/12 - production licence 038 C, awarded 2006	
Discovered	2001	
Development approval	15.06.2007 by the King in Council	
On stream	24.01.2009	
Operator	Talisman Energy Norge AS	
Licensees	Petoro AS	30.00 %
	Talisman Energy Norge AS	70.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	0.7 million scm oil	0.5 million scm oil
	3.4 billion scm gas	2.8 billion scm gas
	0.2 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 3 000 barrels/day, Gas: 0.69 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 4.3 billion (2010 values)	
	NOK 4.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

Development:
Rev is located close to the border between Norwegian and British sector, four kilometres south of the Varg field. The development concept is subsea templates connected to the Armada field on the British continental shelf. The sea depth in the area is 90 - 110 metres.

Reservoir:
The reservoir has an oil zone with a gas cap and is in Upper Jurassic sandstones surrounding a salt structure at about 3 000 metres depth. Pressure measurements have shown that the reservoir is in communication with the Varg field.

Recovery strategy:
The field is produced by pressure depletion.

Transport:
The wellstream is routed through a 9 kilometre long pipeline to the Armada field for processing and further export to the UK.



Ringhorne Øst

Blocks and production licences	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169, awarded 1991
Discovered	2003
Development approval	10.11.2005 by the King in Council
On stream	19.03.2006
Operator	ExxonMobil Exploration & Production Norway AS
Licensees	ExxonMobil Exploration & Production Norway AS 77.38 % Petoro AS 7.80 % Statoil Petroleum AS 14.82 %
Recoverable reserves	**Original:** 11.8 million scm oil; 0.4 billion scm gas **Remaining as of 31.12.2009** 5.7 million scm oil; 0.2 billion scm gas
Production	**Estimated production in 2010:** Oil: 16 000 barrels/day, Gas: 0.05 billion scm
Investment	Total investment is expected to be NOK 0.7 billion (2010 values) NOK 0.6 billion have been invested as of 31.12.2009 (2010 values)
Operating organisation	Stavanger

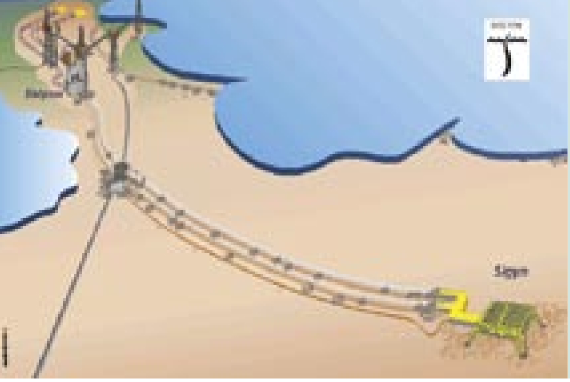
Development:
Ringhorne Øst is an oil field located northeast of Balder in the middle part of the North Sea. The sea depth in the area is about 130 meters. The field is developed by three production wells drilled from the Ringhorne facility on the Balder field.

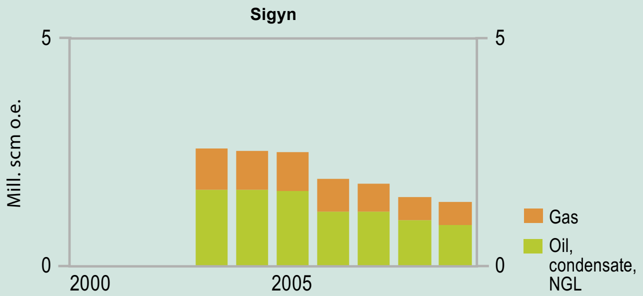
Reservoir:
The reservoir contains oil with associated gas and is in Jurassic sandstones of the Statfjord Formation. The reservoir lies at a depth of approximately 1 940 metres and has very good quality. A 4D seismic survey was conducted in 2009, and will be interpreted in 2010 to plan for new production wells.

Recovery strategy:
The field is recovered by natural water drive from a regional aquifer to the north and east of the structure. All the wells have gas lift to optimise production, and this will be expanded due to increasing water production.

Transport:
The production from Ringhorne Øst is transported to the Balder and Jotun facilities for processing, storage and export.

Status:
The field has entered the decline phase, and is expected to produce until 2023. Two production wells are in the planning phase for drilling and production in 2011/2012.





Sigyn

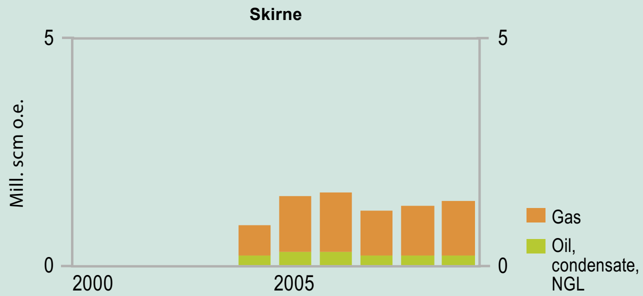
Blocks and production licences	Block 16/7 - production licence 072, awarded 1981	
Discovered	1982	
Development approval	31.08.2001 by the King in Council	
On stream	22.12.2002	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	40.00 %
	Statoil Petroleum AS	60.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	6.7 billion scm gas	1.7 billion scm gas
	2.8 million tonnes NGL	0.8 million tonnes NGL
	4.9 million scm condensate	
Production	**Estimated production in 2010:**	
	Gas: 0.36 billion scm, NGL: 0.11 million tonnes	
Investment	Total investment is expected to be NOK 2.8 billion (2010 values)	
	NOK 2.8 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

Development:
Sigyn is located in the Sleipner area in the middle part of the North Sea. The sea depth in the area is around 70 metres. The field comprises the deposits Sigyn Vest which contains gas and condensate, and Sigyn Øst which contains light oil. The field has been developed with a subsea template tied to Sleipner Øst.

Reservoir:
The main reservoir lies in the Triassic Skagerrak Formation at a depth of approximately 2 700 metres, and the reservoir quality is good.

Recovery strategy:
The field is produced by pressure depletion.

Transport:
The wellstream is controlled from Sleipner Øst and sent through two 12 kilometre long pipelines to the Sleipner A facility. The gas is exported using the dry gas system at Sleipner A. Condensate is transported via the condensate pipeline from Sleipner A to Kårstø.



Skirne

Blocks and production licences	Block 25/5 - production licence 102, awarded 1985	
Discovered	1990	
Development approval	05.07.2002 by the Crown Prince Regent in Council	
On stream	03.03.2004	
Operator	Total E&P Norge AS	
Licensees	Centrica Resources (Norge) AS	20.00 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	10.00 %
	Total E&P Norge AS	40.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	2.1 million scm oil	0.7 million scm oil
	8.7 billion scm gas	2.3 billion scm gas
Production	**Estimated production in 2010:**	
	Oil: 3 000 barrels/day, Gas: 0.94 billion scm	
Investment	Total investment is expected to be NOK 3.5 billion (2010 values)	
	NOK 3.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

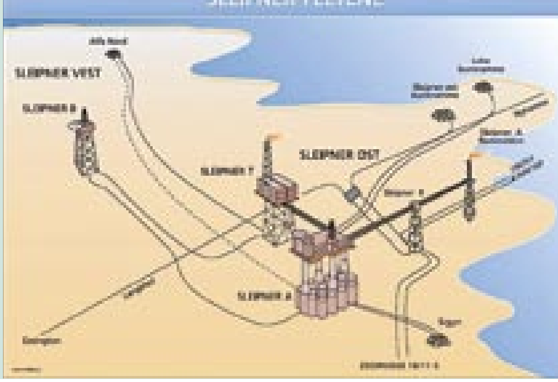
Development:
Skirne, which includes the Byggve deposit, contains gas and condensate and is located east of Heimdal in the middle part of the North Sea. The sea depth in the area is about 120 metres. The field has been developed with two subsea templates tied to Heimdal by a pipeline.

Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The Skirne deposit lies at a depth of approximately 2 370 metres and the Byggve deposit at approximately 2 900 metres. The reservoir quality is good.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
The wellstream from Skirne is transported in a pipeline to the Heimdal facility for processing and further transport of the gas in Vesterled and Statpipe, whereas condensate is transported to Brae in the British sector.

Status:
The lifetime for Skirne is dependent on the lifetime of the Heimdal facility.



Sleipner Vest

Blocks and production licences	Block 15/6 - production licence 029, awarded 1969	
	Block 15/9 - production licence 046, awarded 1976	
Discovered	1974	
Development approval	14.12.1992 by the Storting	
On stream	29.08.1996	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	32.24 %
	Statoil Petroleum AS	58.35 %
	Total E&P Norge AS	9.41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009***
	121.3 billion scm gas	30.9 billion scm gas
	8.5 million tonnes NGL	1.9 million tonnes NGL
	29.6 million scm condensate	5.0 million scm condensate
Production	**Estimated production in 2010:**	
	Gas: 5.98 billion scm, NGL: 0.39 million tonnes, Condensate: 1.03 million scm	
Investment	Total investment is expected to be NOK 35.1 billion (2010 values)	
	NOK 32.7 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

** Gas production from Sleipner Vest and Sleipner Øst is measured collectivily. The remaining reserves show Sleipner Øst and Sleipner Vest in total.*

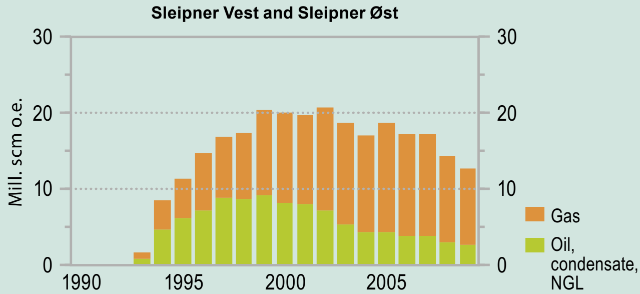
Development:
Sleipner Vest is a gas field in the middle part of the North Sea. The sea depth in the area is about 110 metres. The field is developed with a wellhead facility, Sleipner B, which is remotely operated from the Sleipner A facility on the Sleipner Øst field, and a processing facility, Sleipner T, which is connected by a bridge to Sleipner A. The Alpha Nord segment was developed in 2004 with a subsea template tied back to Sleipner T through an 18 kilometres pipeline.

Reservoir:
Sleipner Vest produces from the Middle Jurassic Sleipner and Hugin Formations. The reservoir depth is approximately 3 450 metres. Most of the reserves are found in the Hugin Formation. The faults in the field are generally not sealing, and communication between the sand deposits is good.

Recovery strategy:
Sleipner Vest is recovered by pressure depletion.

Transport:
Processed gas from Sleipner Vest is routed to Sleipner A for further export, while CO_2 is removed from the gas and injected into the Utsira Formation via a dedicated injection well from Sleipner A. Unstabilised condensate from Sleipner Vest and Sleipner Øst is mixed at Sleipner A and sent to Kårstø for processing to stabilised condensate and NGL products.

Status:
To maintain production at a depleted reservoir pressure, a new compressor started up on Sleipner B in 2009. Drilling and development of several nearby deposits in the near future is being assessed. A drilling program started in 2009. The Beta Vest structure was successfully drilled and proved additional resources. Two wells are planned for 2010.



Sleipner Øst includes total production from Sleipner Vest and Sleipner Øst, and gas production from Gungne.

Sleipner Øst

Blocks and production licences	Block 15/9 - production licence 046, awarded 1976	
Discovered	1981	
Development approval	15.12.1986 by the Storting	
On stream	24.08.1993	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	30.40 %
	Statoil Petroleum AS	59.60 %
	Total E&P Norge AS	10.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009***
	67.3 billion scm gas	30.9 billion scm gas
	12.8 million tonnes NGL	1.9 million tonnes NGL
	26.3 million scm condensate	5.0 million scm condensate
Production	**Estimated production in 2010:**	
	Gas: 0.47 billion scm, NGL: 0.07 million tonnes, Condensate: 0.08 million scm	
Investment	Total investment is expected to be NOK 49.5 billion (2010 values)	
	NOK 47.6 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

** Gas production from Sleipner Vest and Sleipner Øst is measured collectivily. The remaining reserves show Sleipner Øst and Sleipner Vest in total.*

Development:
Sleipner Øst is a gas condensate field in the middle part of the North Sea. The sea depth in the area is 82 metres. The field has been developed with an integrated processing, drilling and accommodation facility with a concrete gravity base structure, Sleipner A. In addition, a riser facility, Sleipner R, which connects Sleipner A to the pipelines for gas transport and a flare stack Sleipner F, have been installed. Two subsea templates have also been installed, one for production from the northern part of Sleipner Øst and one for production of the Loke deposit. Further, the fields Sigyn and Gungne are tied back to Sleipner A. The PDO for Loke was approved in 1991 and production started in 1993. Development of Loke Triassic was approved on 29.08.1995 and production started in 1998.

Reservoir:
The Sleipner Øst and Loke reservoirs are mainly in sandstones of the Ty Formation of Paleocene age and Hugin Formation of Middle Jurassic age. In addition, gas is proven in the Heimdal Formation, overlying the Ty Formation. The reservoir depth is approximately 2 300 metres. There is no pressure communication between the two main reservoir zones. Under the Hugin Formation lies the Triassic Skagerrak Formation. The Skagerrak Formation is the main reservoir at Loke, and has moderate to poor reservoir characteristics.

Recovery strategy:
The Hugin Formation reservoir produces by pressure depletion. The Ty reservoir was produced by dry gas recycling until 2005. To optimise production, the wells are now produced at a reduced inlet pressure.

Transport:
The wellstream from Sleipner Øst is processed on Sleipner A together with the production from Gungne and Sigyn. Condensate from Sleipner Vest and Sleipner Øst is sent to Kårstø for further processing. Processed gas is mixed with gas from Troll and exported via Draupner to Zeebrugge.

Status:
Two new wells were drilled in 2009. Improved recovery through additionally reduced inlet pressure started in 2010.

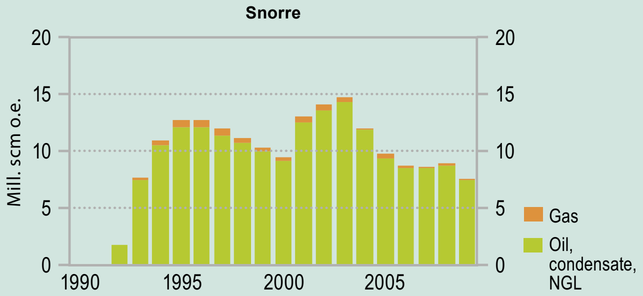
Snorre

Blocks and production licences	Block 34/4 - production licence 057, awarded 1979 Block 34/7 - production licence 089, awarded 1984	
Discovered	1979	
Development approval	27.05.1988 by the Storting	
On stream	03.08.1992	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	11.58 %
	Hess Norge AS	1.04 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	8.28 %
	Statoil Petroleum AS	33.32 %
	Total E&P Norge AS	6.18 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	238.3 million scm oil	68.3 million scm oil
	6.5 billion scm gas	0.5 billion scm gas
	4.7 million tonnes NGL	0.2 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 116 000 barrels/day. Gas: 0.05 billion scm. NGL: 0.04 million tonnes	
Investment	Total investment is expected to be NOK 126.3 billion (2010 values) NOK 92.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
Snorre is an oil field in the Tampen area in the northern part of the North Sea. The sea depth in the area is 300 - 350 metres. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. Snorre A also has a separate process module for production from the Vigdis field. A subsea template with ten well slots, Snorre UPA, is located centrally on the field and connected to Snorre A. Snorre B is located in the northern part of the field and is a semi-submersible integrated drilling, processing and accommodation facility. An amended PDO for Snorre, including a new processing module on Snorre A for prosessing oil from Vigdis, was approved on 16.12.1994. The PDO for Snorre B was approved on 08.06.1998. Snorre B came on stream in June 2001.

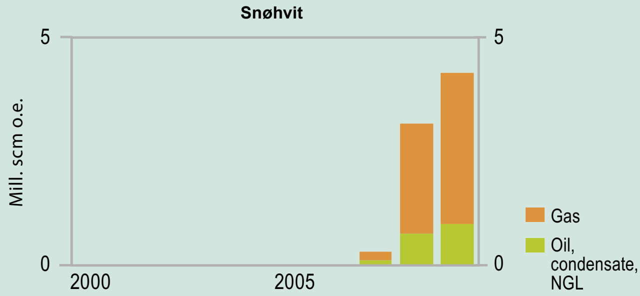
Reservoir:
The Snorre field consists of several large fault blocks. The reservoir contains Lower Jurassic and Triassic sandstones of the Statfjord and Lunde Formations. The reservoir depth is 2 000 - 2 700 metres. The reservoir has a complex structure with many alluvial channels and internal flow barriers.

Recovery strategy:
Snorre is produced by pressure maintenance by water injection, gas injection and water alternating gas injection (WAG). Foam assisted injection (FAWAG) has also been tested in parts of the reservoir. Lack of injection capacity and wells has over time led to lower than desired pressure in parts of the field. All gas produced from both Snorre A and Snorre B has in recent years been re-injected in the reservoir.



Transport:
Oil and gas are separated in two stages at Snorre A before transport in separate pipelines to Statfjord A for final processing and export. The oil is loaded onto shuttle tankers at Statfjord and the gas is sent through the Statpipe pipeline to Kårstø. Processed oil from Snorre B is routed by pipeline to Statfjord B for storage and loading to shuttle tankers. All gas from Snorre B is normally re-injected into the reservoir, but may also be sent by pipeline to Snorre A and exported via Statfjord A. A long-term solution for Snorre, after the present export via Statfjord A ceases, is being worked on.

Status:
In 2007 it was decided to increase the processing capacities for production and injection of water. For many years, the licensees have been working on plans for future and long-term production from the field in the project Snorre 2040. This is based on a significant potential for increasing oil recovery. Important elements in the project are: drilling of more wells, expanded gas injection, modification of facilities and possibly new infrastructure. The new, long-term development plan for Snorre is expected in 2010.



Snøhvit

Blocks and production licences	Block 7120/5 - production licence 110, awarded 1985	
	Block 7120/6 - production licence 097, awarded 1984	
	Block 7120/7 - production licence 077, awarded 1982	
	Block 7120/8 - production licence 064, awarded 1981	
	Block 7120/9 - production licence 078, awarded 1982	
	Block 7121/4 - production licence 099, awarded 1984	
	Block 7121/5 - production licence 110, awarded 1985	
	Block 7121/7 - production licence 100, awarded 1984	
Discovered	1984	
Development approval	07.03.2002 by the Storting	
On stream	21.08.2007	
Operator	Statoil Petroleum AS	
Licensees	GDF SUEZ E&P Norge AS	12.00 %
	Hess Norge AS	3.26 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.81 %
	Statoil Petroleum AS	33.53 %
	Total E&P Norge AS	18.40 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	160.6 billion scm gas	154.8 billion scm gas
	6.4 million tonnes NGL	6.1 million tonnes NGL
	18.1 million scm condensate	16.9 million scm condensate
Production	**Estimated production in 2010:**	
	Gas: 5.76 billion scm, NGL: 0.30 million tonnes, Condensate: 0.93 million scm	
Investment*	Total investment is expected to be NOK 26.7 billion (2010 values)	
	NOK 10.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Harstad and Stjørdal	

** Total investment, including the land facilities, is expected to be 90.5 billion (2010 values).*

Development:
Snøhvit is located in the Barents Sea in the central part of the Hammerfest basin, at a sea depth of 310 - 340 metres. Snøhvit is a gas field with condensate and an underlying thin oil zone. The field comprises several discoveries and deposits in the Askeladd and Albatross structures in addition to Snøhvit. The approved PDO for the gas resources includes subsea templates for 19 production wells and one injection well for CO_2.

Reservoir:
The reservoirs contain gas, condensate and oil in Lower and Middle Jurassic sandstones of the Stø and Nordmela Formations. The reservoir depth is approximately 2 300 meters.

Recovery strategy:
The recovery strategy is pressure depletion. The development does not include recovery of the oil zone.

Transport:

The wellstream, containing natural gas inclusive CO_2, NGL and condensate, is transported through a 160 kilometre long pipeline to the facility at Melkøya for processing and export. The gas is processed and cooled down to liquid form (LNG) at Melkøya. The CO_2 content in the gas is separated at Melkøya and sent back to the field to be re-injected in a deeper formation. LNG is shipped to the market.

Status:

There were major turnarounds in the autumn of 2009 for equipment replacement. The Melkøya facility is now producing at 100 % of estimated capacity.

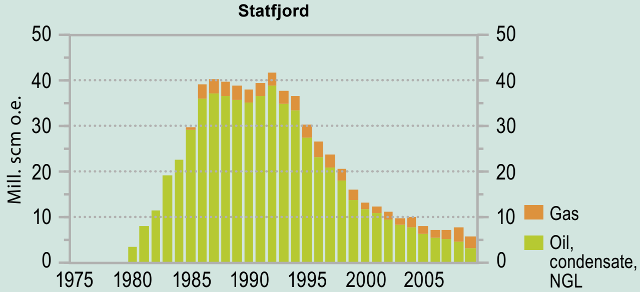
Statfjord

Blocks and production licences	Block 33/12 - production licence 037, awarded 1973 Block 33/9 - production licence 037, awarded 1973 The Norwegian part of the field is 85.47%, the British part is 14.53%	
Discovered	1974	
Development approval	16.06.1976 by the Storting	
On stream	24.11.1979	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	8.55 %
	ConocoPhillips Skandinavia AS	10.33 %
	Enterprise Oil Norge AS	0.89 %
	ExxonMobil Exploration & Production Norway AS	21.37 %
	Statoil Petroleum AS	44.34 %
	Centrica Resources Limited	9.69 %
	ConocoPhillips (U.K.) Limited.	4.84 %
Recoverable reserves (Norwegian part)	**Original:**	**Remaining as of 31.12.2009**
	565.8 million scm oil	5.1 million scm oil
	74.3 billion scm gas	13.3 billion scm gas
	23.3 million tonnes NGL	7.3 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 27 000 barrels/day, Gas: 1.34 billion scm, NGL: 0.73 million tonnes	
Investment	Total investment is expected to be NOK 167.7 billion (2010 values) NOK 157.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Sotra and Florø	

Development:
Statfjord is an oil field straddling the border between the Norwegian and British sectors in the Tampen area. The sea depth in the area is 150 metres. The field has been developed with three fully integrated facilities; Statfjord A, Statfjord B and Statfjord C. Statfjord A is centrally positioned on the field, and came on stream in 1979. Statfjord B is located in the southern part of the field, and came on stream in 1982. Statfjord C is situated in the northern part of the field, and came on stream in 1985. Statfjord B and Statfjord C have similar construction. The satellite fields Statfjord Øst, Statfjord Nord and Sygna have a separate inlet separator on Statfjord C. The PDO for Statfjord Late Life was approved on 08.06.2005.

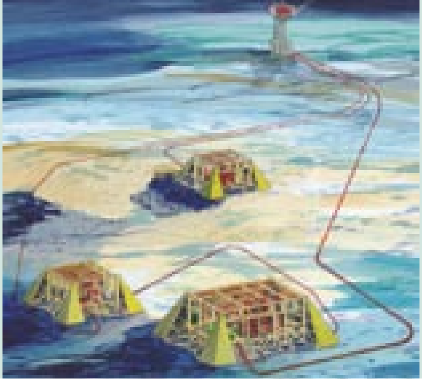
Reservoir:
The Statfjord reservoirs lie at a depth of 2 500 - 3 000 metres in a large fault block tilted towards the west, and in a number of smaller fault compartments along the east flank. The reservoirs are in Jurassic sandstones of the Brent Group and the Cook and Statfjord Formations. The Brent Group and Statfjord Formation have excellent reservoir quality.

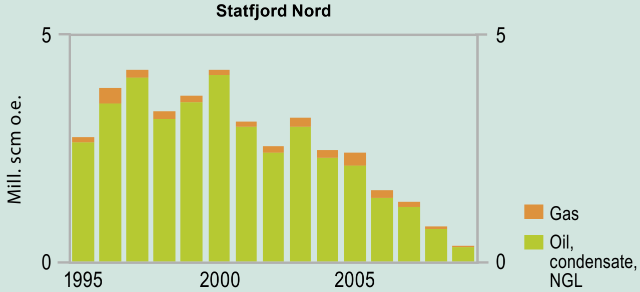
Recovery strategy:
Statfjord was originally produced by pressure support from water alternating gas injection (WAG), water injection and partial gas injection. Statfjord Late Life entails that all injection has now ceased, and the field is now produced by depressurisation in order to liberate gas from remaining oil. Blowdown of the reservoir pressure in the Brent Formation started in the autumn of 2008. Statfjord Late Life is expected to prolong the lifetime of the field by ten years and increase the recovery of both oil and gas.



Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded to tankers from one of the two oil loading systems at the field. From 2007, gas is exported through a new pipe, Tampen Link, which is routed via the Far North Liquids and Gas System (FLAGS) pipeline to the United Kingdom. The UK licensees route their share of the gas through the FLAGS pipeline from Statfjord B to St. Fergus in Scotland.

Status:
The facilities are being modified as part of Statfjord Late Life, and wells were drilled and repaired in 2009. There are plans to drill 60 new oil, water and gas wells during Statfjord Late Life. At the end of September 2009, 33 of these wells were completed. The lifetime of Statfjord A, B and C, and the continued tie-in of Snorre to Statfjord A and B, is now being evaluated in cooperation with the licensees in the Snorre field.





Statfjord Nord

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973	
Discovered	1977	
Development approval	11.12.1990 by the Storting	
On stream	23.01.1995	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	10.00 %
	ConocoPhillips Skandinavia AS	12.08 %
	Enterprise Oil Norge AS	1.04 %
	ExxonMobil Exploration & Production Norway AS	25.00 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	21.88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	39.3 million scm oil	3.6 million scm oil
	2.1 billion scm gas	0.3 million tonnes NGL
	1.1 million tonnes NGL	
Production	**Estimated production in 2010:**	
	Oil: 5 000 barrels/day, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 9.9 billion (2010 values)	
	NOK 9.7 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

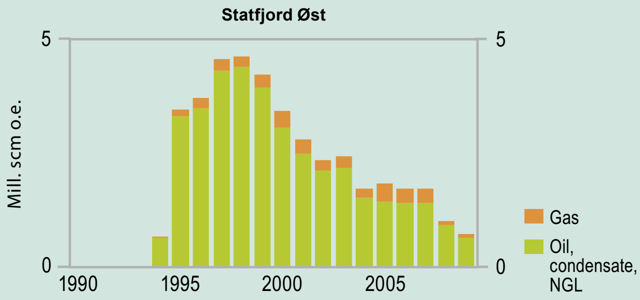
Development:
Statfjord Nord is an oil field located approximately 17 kilometres north of Statfjord in the Tampen area. The sea depth in the area is 250 - 290 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production and one is for water injection. One well slot is used for water injection at the Sygna field.

Reservoir:
The Statfjord Nord reservoirs consist of Middle Jurassic sandstones of the Brent Group (Tarbert, Etive and Rannoch Formations), and Upper Jurassic sandstones. The reservoirs lie at a depth of approximately 2 600 metres and are of good quality.

Recovery strategy:
The field produces with partial pressure support from water injection.

Transport:
The wellstream is routed through two pipelines to Statfjord C for processing, storage and export. Statfjord Nord, Sygna and Statfjord Øst have a shared process module on Statfjord C.

Status:
It is being considered if water alternating gas injection (WAG) can be a method for improved oil recovery. Final decision is expected in 2010. The water injection has in periods been shut down.



Statfjord Øst

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973	
	Block 34/7 - production licence 089, awarded 1984	
Discovered	1976	
Development approval	11.12.1990 by the Storting	
On stream	24.09.1994	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	5.00 %
	ConocoPhillips Skandinavia AS	6.04 %
	Enterprise Oil Norge AS	0.52 %
	ExxonMobil Exploration & Production Norway AS	17.75 %
	Idemitsu Petroleum Norge AS	4.80 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.40 %
	Statoil Petroleum AS	31.69 %
	Total E&P Norge AS	2.80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	35.7 million scm oil	1.3 million scm oil
	3.8 billion scm gas	0.1 billion scm gas
	2.0 million tonnes NGL	0.7 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 7 000 barrels/day, Gas: 0.04 billion scm, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 9.6 billion (2010 values)	
	NOK 9.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

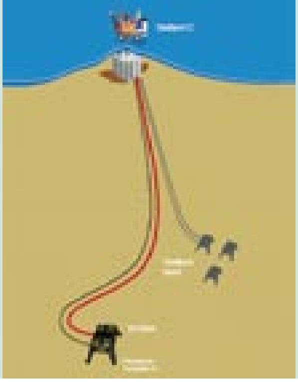
Development:
Statfjord Øst is an oil field located approximately 7 kilometres northeast of the Statfjord field in the Tampen area. The sea depth in the area is 150 - 190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two of the templates are for production and one for water injection. In addition, one production well is drilled from Statfjord C.

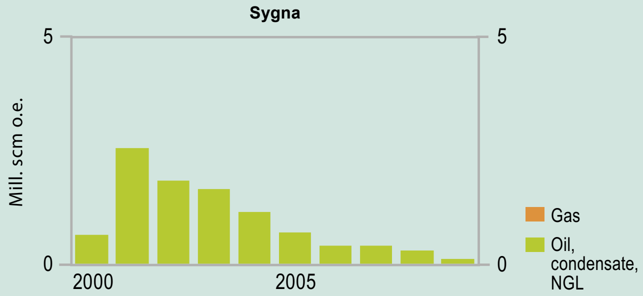
Reservoir:
The reservoir consists of Middle Jurassic sandstones belonging to the Brent Group. The reservoir depth is approximately 2 400 metres.

Recovery strategy:
The field is produced by partial pressure support from water injection.

Transport:
The wellstream is routed through two pipelines to Statfjord C for processing, storage and export. Statfjord Øst, Sygna and Statfjord Nord have a shared process module on Statfjord C.

Status:
Production from Statfjord Øst is below prognosis because water injection wells have been shut down. The field is affected by pressure depletion from blowdown of Statfjord. The drilling of a new production well from Statfjord C to Statfjord Øst is being considered.





Sygna

Blocks and production licences	Block 33/9 - production licence 037, awarded 1973	
	Block 34/7 - production licence 089, awarded 1984	
Discovered	1996	
Development approval	30.04.1999 by the King in Council	
On stream	01.08.2000	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	5.50 %
	ConocoPhillips Skandinavia AS	6.65 %
	Enterprise Oil Norge AS	0.57 %
	ExxonMobil Exploration & Production Norway AS	18.48 %
	Idemitsu Petroleum Norge AS	4.32 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	1.26 %
	Statoil Petroleum AS	30.71 %
	Total E&P Norge AS	2.52 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	10.7 million scm oil	1.0 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 2.9 billion (2010 values)	
	NOK 2.9 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

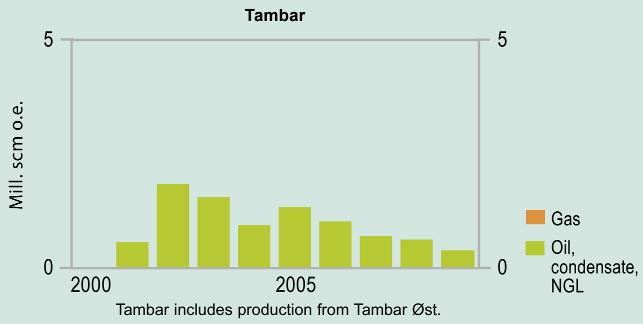
Development:
Sygna is an oil field located north of the Statfjord Nord field in the Tampen area. The sea depth in the area is about 300 metres. The field has been developed with one subsea template with four well slots, connected to Statfjord C.

Reservoir:
The Sygna reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 2 650 metres. The reservoir quality is good.

Recovery strategy:
The field is produced by water injection through a well drilled from Statfjord Nord.

Transport:
The wellstream is sent by pipeline to Statfjord C for processing, storage and export. Statfjord Nord, Statfjord Øst and Sygna have a shared process module on Statfjord C.

Status:
The plan is to sidetrack wells to new areas and maintain reservoir pressure by water injection. Alternative recovery methods are also being evaluated.



Tambar

Blocks and production licences	Block 1/3 - production licence 065, awarded 1981	
	Block 2/1 - production licence 019 B, awarded 1977	
Discovered	1983	
Development approval	03.04.2000 by the King in Council	
On stream	15.07.2001	
Operator	BP Norge AS	
Licensees	BP Norge AS	55.00 %
	DONG E&P Norge AS	45.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	8.9 million scm oil	0.7 million scm oil
	2.0 billion scm gas	0.2 billion scm gas
	0.3 million tonnes NGL	
Production	**Estimated production in 2010:**	
	Oil: 4 000 barrels/day, Gas: 0.06 billion scm	
Investment	Total investment is expected to be NOK 3.0 billion (2010 values)	
	NOK 2.9 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Tambar is an oil field located southeast of the Ula field in the southern part of the North Sea. The sea depth in the area is 68 metres. The field has been developed with a remotely controlled wellhead facility without processing equipment.

Reservoir:
The reservoir consists of Upper Jurassic sandstones of the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4 100 - 4 200 metres and the reservoir characteristics are generally very good.

Recovery strategy:
The field is producing by pressure depletion and limited aquifer drive. The production went off plateau in 2002 and is now declining.

Transport:
The oil is transported to Ula through a pipeline which was installed in June 2007. After processing at Ula, the oil is exported in the existing pipeline system to Teesside via Ekofisk while the gas is injected in the Ula reservoir to improve oil recovery.

Status:
A multi-phase pump, installed in 2008, to reduce the wellhead pressure and increase recovery from Tambar, has failed and is not in use. A major challenge in the future is that high water cut in the wells restrains production.

Tambar Øst

Blocks and production licences	Block 1/3 - production licence 065, awarded 1981	
	Block 2/1 - production licence 019 B, awarded 1977	
	Block 2/1 - production licence 300, awarded 2003	
Discovered	2007	
Development approval	28.06.2007	
On stream	02.10.2007	
Operator	BP Norge AS	
Licensees	BP Norge AS	46.20 %
	DONG E&P Norge AS	43.24 %
	Norske AEDC A/S	0.80 %
	Talisman Energy Norge AS	9.76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	0.3 million scm oil	0.1 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 1 000 barrels/day	
Investment	Total investment is expected to be NOK 1.2 billion (2010 values)	
	NOK 1.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

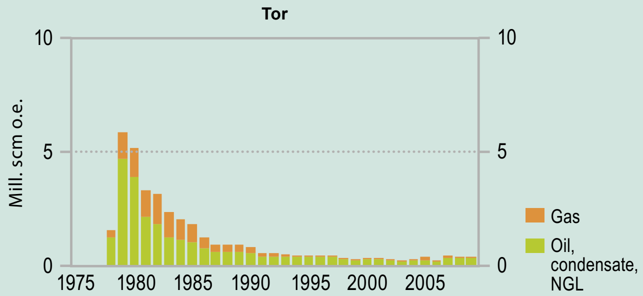
Development:
Tambar Øst has been developed with one production well drilled from the Tambar facility.

Reservoir:
The reservoir is in sandstones of Late Jurassic age, deposited in a shallow marine environment. The reservoir lies at a depth of 4 050 – 4 200 meters and the quality varies.

Recovery strategy:
The field is producing by pressure depletion and limited aquifer drive.

Transport:
The oil is transported to Ula via Tambar. After processing at Ula, the oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is used for gas injection in the Ula reservoir to improve oil recovery.

Status:
Production from Tambar Øst has not met expectations and the reserve estimates have been reduced.



Tor

Blocks and production licences	Block 2/4 - production licence 018, awarded 1965	
	Block 2/5 - production licence 006, awarded 1965	
Discovered	1970	
Development approval	04.05.1973	
On stream	28.06.1978	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	30.66 %
	Eni Norge AS	10.82 %
	Petoro AS	3.69 %
	Statoil Petroleum AS	6.64 %
	Total E&P Norge AS	48.20 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	23.5 million scm oil	0.3 million scm oil
	10.9 billion scm gas	0.1 billion scm gas
	1.2 million tonnes NGL	
Production	**Estimated production in 2010:**	
	Oil: 4 000 barrels/day, Gas: 0.02 billion scm	
Investment	Total investment is expected to be NOK 11.3 billion (2010 values)	
	NOK 11.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

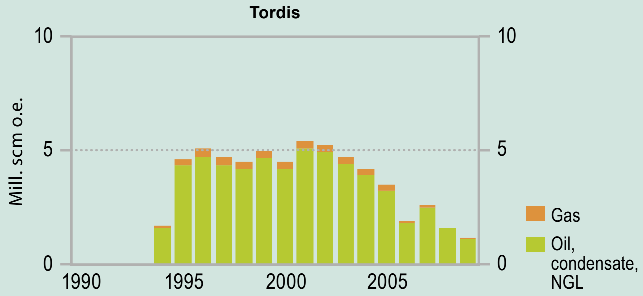
Development:
Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The sea depth in the area is about 70 metres. The field has been developed with a combined wellhead and processing facility tied to Ekofisk.

Reservoir:
The main reservoir consists of fractured chalk of the Tor Formation of Late Cretaceous age. The reservoir lies at a depth of approximately 3 200 metres. The Ekofisk Formation of Early Paleocene age also contains oil, but has poorer reservoir quality. So far, minor volumes have been produced from this formation.

Recovery strategy:
Tor was originally produced by pressure depletion. In 1992, limited water injection commenced. The facility has subsequently been upgraded and the scope of water injection has been expanded. All five wells are producing with gas lift.

Transport:
Oil and gas are transported by pipelines to the processing facility at Ekofisk J. Gas from the Ekofisk area is transported by pipeline to Emden, while the oil, also containing NGL fractions, is sent via pipeline to Teesside.

Status:
The Tor facility has limited lifetime and it is being considered how to recover the remaining resources in the long term. This will most likely require a new development of the field.



Tordis

Blocks and production licences	Block 34/7 - production licence 089, awarded 1984	
Discovered	1987	
Development approval	14.05.1991 by the Storting	
On stream	03.06.1994	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	Statoil Petroleum AS	41.50 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	60.3 million scm oil	6.5 million scm oil
	5.3 billion scm gas	1.5 billion scm gas
	1.7 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 20 000 barrels/day, Gas: 0.02 billion scm, NGL: 0.01 million tonnes	
Investment	Total investment is expected to be NOK 16.5 billion (2010 values)	
	NOK 15.5 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

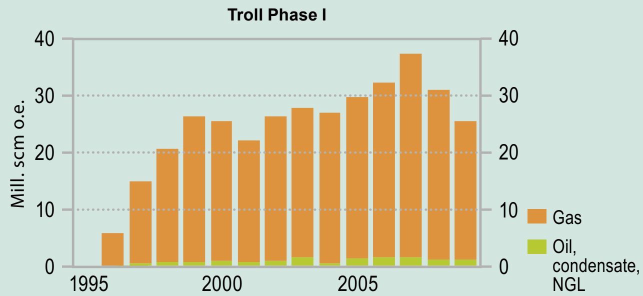
Development:
Tordis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The sea depth in the area is approximately 200 metres. The field has been developed with a central subsea manifold tied back to Gullfaks C. Seven separate satellite wells and two subsea templates are tied back to the manifold. In addition, a subsea separator was installed at the field in 2007. Injection water is transported by pipeline from Gullfaks C. Tordis comprise four deposits: Tordis, Tordis Øst, Borg and 34/7-25 S. The PDO for Tordis Øst was approved on 13.10.1995. The PDO for Borg was approved on 29.06.1999. An amended PDO for Tordis (Tordis IOR) was approved on 16.12.2005.

Reservoir:
The reservoirs in Tordis and Tordis Øst consist of Middle Jurassic sandstones of the Brent Group. The reservoir in Borg consists of Upper Jurassic sandstones in the intra-Draupne Formation, and the reservoir in 34/7-25 S consists of sandstones of the Brent Group and sandstones of Late Jurassic age. The Tordis reservoirs lie at a depth of 2 000 - 2 500 metres.

Recovery strategy:
Production is accomplished by partial pressure maintenance and by water injection and natural aquifer drive. Pressure at Borg is fully maintained using water injection. Tordis Øst is recovered with pressure support from natural aquifer drive. The process facility at Gullfaks is modified and Tordis is now produced at low pressure, which results in increased oil recovery.

Transport:
The wellstream from Tordis is transported through two pipelines to Gullfaks C for processing. The oil is then exported by tankers, while the gas is routed through Statpipe to Kårstø.

Status:
The Tordis subsea separator has been shut down since 2008, when a leakage to the seabed from the injection well was discovered. All production is presently sent directly to Gullfaks for processing. An alternative solution for injection of produced water is being evaluated.



Troll

The Troll field lies in the northern part of the North Sea, about 65 kilometres west of Kollsnes. The water depth in the area is more than 300 metres. The field has huge gas resources and one of the largest oil volumes remaining on the Norwegian continental shelf. Troll has two main structures: Troll Øst and Troll Vest. About two-thirds of the recoverable gas reserves lie in Troll Øst. A thin oil zone underlies the gas throughout the Troll field, but so far only in Troll Vest is this oil zone of sufficient thickness to be commercial, 11 - 27 metres. In 2007, an oil column of 6 - 9 metres was proven in the northern part of Troll Øst. A test production of oil from this part of Troll started in November 2008. A phased development has been pursued, with Phase I recovering gas reserves in Troll Øst and Phase II focused on the oil reserves in Troll Vest. The gas reserves in Troll Vest will be developed in a future phase III. The Troll licensees are conducting studies to plan for further development of the field. Troll was the largest producer of both oil and gas on the Norwegian continental shelf in the period 2000 – 2004.

Troll I

Blocks and production licences	Block 31/2 - production licence 054, awarded 1979	
	Block 31/3 - production licence 085, awarded 1983	
	Block 31/3 - production licence 085 C, awarded 2002	
	Block 31/3 - production licence 085 D, awarded 2006	
	Block 31/5 - production licence 085, awarded 1983	
	Block 31/6 - production licence 085, awarded 1983	
	Block 31/6 - production licence 085 C, awarded 2002	
Discovered	1983	
Development approval	15.12.1986 by the Storting	
On stream	09.02.1996	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	Statoil Petroleum AS	30.58 %
	Total E&P Norge AS	3.69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	1331.2 billion scm gas	970.6 billion scm gas
	25.7 million tonnes NGL	21.5 million tonnes NGL
	1.6 million scm condensate	
Production	**Estimated production in 2010:**	
	Gas: 31.01 billion scm, NGL: 1.12 million tonnes	
Investment	Total investment is expected to be NOK 96.9 billion (2010 values)	
	NOK 73.0 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

Development:
Troll Phase I has been developed with Troll A which is a fixed wellhead and compression facility with a concrete substructure. Troll A is powered by electricity supplied from land. An updated development plan involving the transfer of gas processing to Kollsnes was approved in 1990. Kollsnes was separated from the unitised Troll field in 2004, and the Kollsnes terminal is currently operated by Gassco as part of the Gassled joint venture. The gas compression capacity at Troll A was increased in 2004/2005. The Troll Oseberg Gas Injection (TOGI) subsea template is also located at Troll Øst. Gas was exported from this template to Oseberg for injection. The TOGI decommissioning plan involving removal of the subsea template was approved in 2005.

Reservoir:
The gas and oil reservoirs in the Troll Øst and Troll Vest structures consist primarily of shallow marine sandstones belonging to the Sognefjord Formation of Late Jurassic age. Part of the reservoir is also in the Fensfjord Formation below the Sognefjord Formation. The field consists of three relatively large rotated fault blocks. The fault block to the east constitutes Troll Øst. The reservoir depth at Troll Øst is about 1 330 metres. Pressure communication between Troll Øst and Troll Vest has been proven. Previously, the oil column in Troll Øst was mapped to be 0 - 4 metres thick. A well drilled in 2007 proved an oil column of 6 - 9 metres in the Fensfjord Formation in the northern segment of Troll Øst.

Recovery strategy:
The gas in Troll Øst is recovered by pressure depletion through 39 wells drilled from Troll A.

Transport:
The gas from Troll Øst and Troll Vest is transported through two multi-phase pipelines to the gas processing plant at Kollsnes. The condensate is separated from the gas, and transported by pipeline partly to the Sture terminal, and partly to Mongstad. The dry gas is transported in Zeepipe II A and II B.

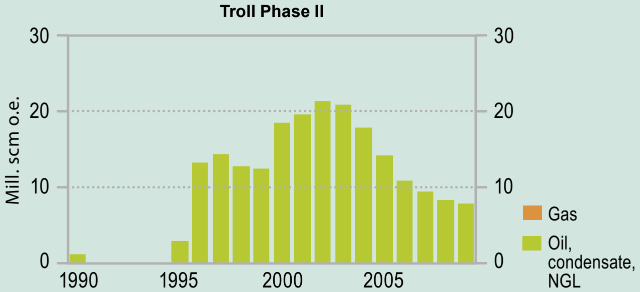
Status:
Test production of oil from the northern part of Troll Øst has started. The licensees will consider development of this area when experience from the test production is available.

Troll II

Blocks and production licences	Block 31/2 - production licence 054, awarded 1979	
	Block 31/3 - production licence 085, awarded 1983	
	Block 31/3 - production licence 085 C, awarded 2002	
	Block 31/3 - production licence 085 D, awarded 2006	
	Block 31/5 - production licence 085, awarded 1983	
	Block 31/6 - production licence 085, awarded 1983	
	Block 31/6 - production licence 085 C, awarded 2002	
Discovered	1979	
Development approval	18.05.1992 by the Storting	
On stream	19.09.1995	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	8.10 %
	ConocoPhillips Skandinavia AS	1.62 %
	Petoro AS	56.00 %
	Statoil Petroleum AS	30.58 %
	Total E&P Norge AS	3.69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	248.5 million scm oil	42.0 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 113 000 barrels/day	
Investment	Total investment is expected to be NOK 123.5 billion (2010 values)	
	NOK 104.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Troll Phase II has been developed with Troll B, a floating concrete accommodation and production facility, and Troll C, which is a semi-submersible accommodation and production facility of steel. The oil in Troll Vest is produced by means of several subsea templates tied back to Troll B and Troll C by flowlines. Troll Pilot, which was installed in 2000 at a depth of 340 meters, is a subsea facility for separation and re-injection of produced water. The Troll C facility is also utilised for production from the Fram field. The Troll C development was approved in 1997. There have been several PDO approvals in connection with various subsea templates at Troll Vest.

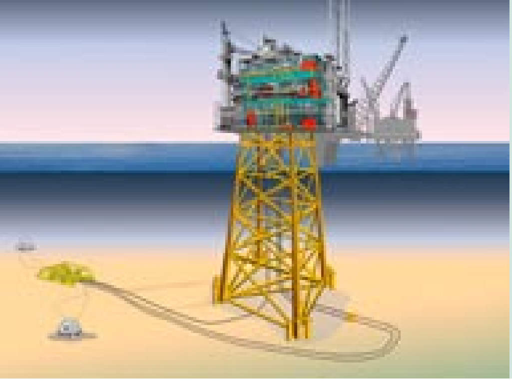
Reservoir:
The gas and oil in the Troll Øst and Troll Vest structures are found primarily in the Sognefjord Formation which consists of shallow marine sandstones of Late Jurassic age. Part of the reservoir is also in the underlying Fensfjord Formation. The field comprises three relatively large rotated fault blocks. The oil in the Troll Vest oil province is encountered in a 22–26 metre thick oil column under a small gas cap, located at 1 360 metres depth. The Troll Vest gas province has an oil column of about 12-14 metres under a gas column up to 200 metres in thickness. A significant volume of residual oil is encountered immediately below the Troll Vest oil column. There is a minor oil discovery in the Middle Jurassic Brent Group, below the main oil reservoir.

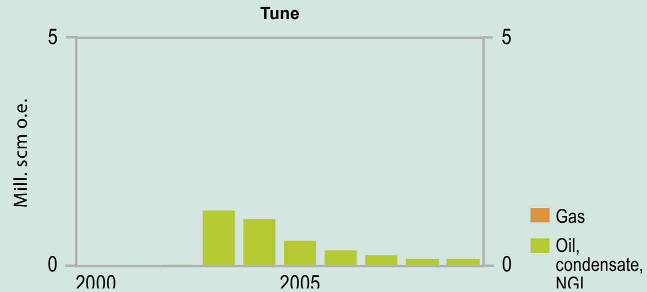


Recovery strategy:
The oil in Troll Vest is produced by means of long horizontal wells which penetrate the thin oil zone immediately above the oil-water contact. The recovery strategy is based primarily on pressure depletion, but this is accompanied by a simultaneous expansion of both the gas cap above the oil zone and the underlying water zone. In the Troll Vest oil province, some of the produced gas has been re-injected into the reservoir to optimise oil production. One important aspect of the strategy has been to recover the oil rapidly, since the volumes of oil that can be recovered will decrease as pressure declines at Troll Øst. For this reason, limits have been placed on the rates of gas production from Troll Øst.

Transport:
The gas from Troll Øst and Troll Vest is transported through two multi-phase pipelines to the gas processing plant at Kollsnes. Condensate is separated from the gas and transported onwards by pipelines, partly to the Sture terminal, partly to Mongstad. The dry gas is transported through Zeepipe II A and Zeepipe II B. The oil from Troll B and Troll C is transported in the Troll Oil Pipelines I and II, respectively, to the oil terminal at Mongstad.

Status:
Drilling on Troll Vest with horizontal production wells from subsea templates continues with three mobile drilling facilities simultaneously. There are presently about 120 active oil production wells at Troll Vest. Over the last few years, decisions have been made every year to drill new production wells to increase the oil reserves in Troll, and there are still a number of wells in the drilling plan. Several multi-branch wells have been drilled, with up to seven branches in the same well. In addition, studies have been initiated with regard to water injection. Gas injection in the Troll Vest gas province is planned to start in 2011.





Tune

Blocks and production licences	Block 30/5 - production licence 034, awarded 1969 Block 30/6 - production licence 053, awarded 1979 Block 30/8 - production licence 190, awarded 1993	
Discovered	1996	
Development approval	17.12.1999 by the King in Council	
On stream	28.11.2002	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS Statoil Petroleum AS Total E&P Norge AS	40.00 % 50.00 % 10.00 %
Recoverable reserves	**Original:** 3.2 million scm oil 18.0 billion scm gas 0.2 million tonnes NGL	**Remaining as of 31.12.2009** 0.2 million scm oil 1.8 billion scm gas 0.1 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 1 000 barrels/day, Gas: 0.81 billion scm	
Investment	Total investment is expected to be NOK 6.2 billion (2010 values) NOK 6.2 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

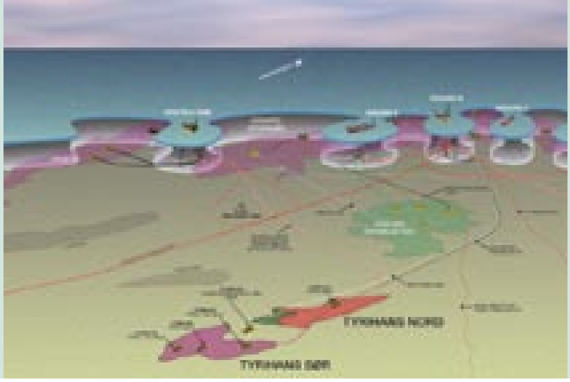
Development:
Tune is a gas condensate field located about 10 kilometres west of the Oseberg Field Centre in the northern part of the North Sea. The sea depth in the area is approximately 95 metres. The field has been developed with a subsea template and a satellite well tied to Oseberg. In March 2004, a PDO exemption was granted for development of the northern part of the field, while a similar exemption was granted for the southern part of the field in May 2005 (Tune Phase III).

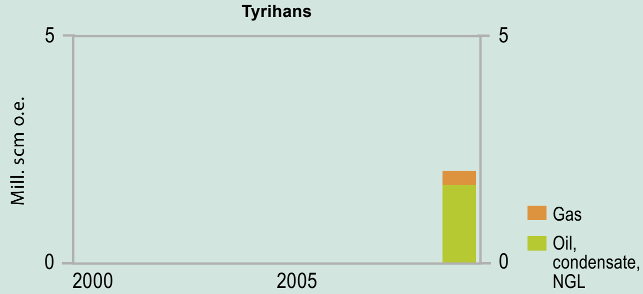
Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group and is divided into several inclined fault blocks. The reservoir depth is approximately 3 400 metres.

Recovery strategy:
The field is recovered by pressure depletion. Low pressure production has been started.

Transport:
The wellstream from Tune is transported in pipelines to the Oseberg Field Centre, where the condensate is separated out and transported to the Sture terminal through the Oseberg Transport System (OTS). Gas from Tune is injected in Oseberg, while the licensees can export a corresponding volume of sales gas from Oseberg.

Status:
A new production well in the southern part of the field was drilled and came on stream in 2009.





Tyrihans

Blocks and production licences	Block 6406/3 - production licence 073 B, awarded 2004	
	Block 6406/3 - production licence 091, awarded 1984	
	Block 6407/1 - production licence 073, awarded 1982	
Discovered	1983	
Development approval	16.02.2006 by the Storting	
On stream	08.07.2009	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	6.23 %
	ExxonMobil Exploration & Production Norway AS	11.75 %
	Statoil Petroleum AS	58.84 %
	Total E&P Norge AS	23.18 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	29.6 million scm oil	28.0 million scm oil
	35.5 billion scm gas	35.3 billion scm gas
	6.5 million tonnes NGL	6.5 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 57 000 barrels/day, Gas: 0.12 billion scm, NGL: 0.03 million tonnes	
Investment	Total investment is expected to be NOK 16.1 billion (2010 values)	
	NOK 12.8 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	

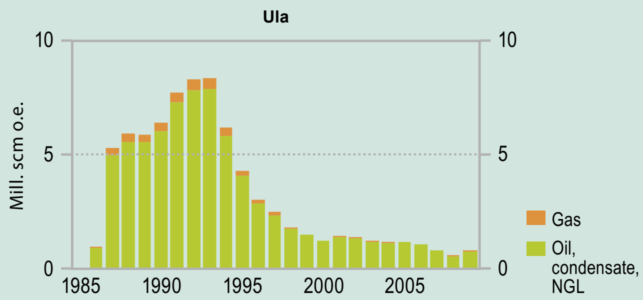
Development:
Tyrihans is located in the Norwegian Sea about 25 kilometres southeast of the Åsgard field. The sea depth in the area is about 270 metres. Tyrihans consists of the discoveries 6407/1-2 Tyrihans Sør, which was discovered in 1983, and 6407/1-3 Tyrihans Nord, discovered in 1984. The development concept is five subsea templates tied to Kristin, four for production and gas injection and one for water injection.

Reservoir:
Tyrihans Sør has an oil column with a condensate rich gas cap. Tyrihans Nord contains gas condensate with an underlying oil zone. The Garn Formation of Middle Jurassic age constitutes the main reservoir in both deposits and lies at about 3 500 metres. The reservoir is homogenous and the quality is good.

Recovery strategy:
In the first years, the recovery is based on gas injection from Åsgard B into Tyrihans Sør. In addition, subsea pumps will be used for injection of sea water to increase recovery. It has also been decided to produce the oil zone in Tyrihans Nord.

Transport:
Oil and gas from Tyrihans are transported in pipeline to Kristin for processing and further transport.

Status:
The field came on stream in July 2009, and gas injection from Åsgard was started in October 2009.



Ula

Blocks and production licences	Block 7/12 - production licence 019, awarded 1965	
	Block 7/12 - production licence 019 B, awarded 1977	
Discovered	1976	
Development approval	30.05.1980 by the Storting	
On stream	06.10.1986	
Operator	BP Norge AS	
Licensees	BP Norge AS	80.00 %
	DONG E&P Norge AS	20.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	91.8 million scm oil	21.9 million scm oil
	3.9 billion scm gas	0.9 million tonnes NGL
	3.4 million tonnes NGL	
Production	**Estimated production in 2010:**	
	Oil: 13 000 barrels/day, NGL: 0.02 million tonnes	
Investment	Total investment is expected to be NOK 34.0 billion (2010 values)	
	NOK 28.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

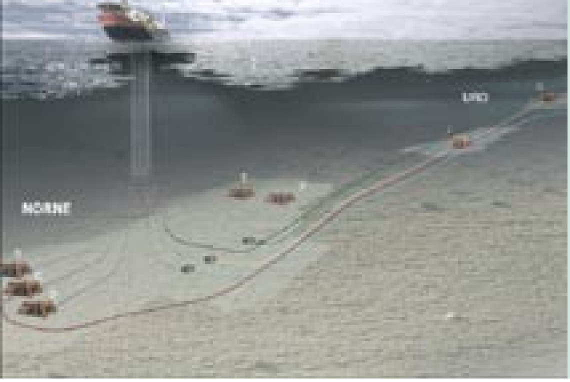
Development:
Ula is an oil field in the southern part of the North Sea. The sea depth in the area is about 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges. The wellstream from Blane was tied to the Ula field for processing in September 2007. The gas capacity at Ula was upgraded in 2008 with a new gas processing and gas injection module (UGU) that doubled the capacity.

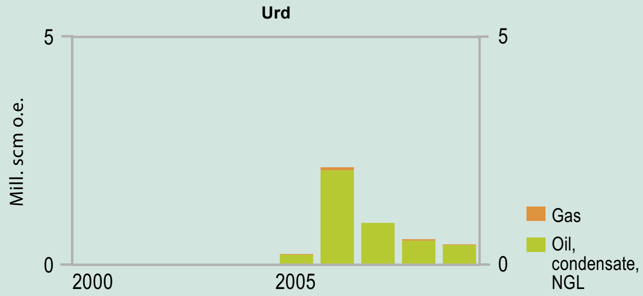
Reservoir:
The main reservoir is at a depth of 3 345 metres in the Upper Jurassic Ula Formation. The reservoir consists of three layers and two of them are producing good.

Recovery strategy:
Oil was initially recovered by pressure depletion, but after some years water injection was implemented to improve recovery. Water alternating gas injection (WAG) started in 1998. The WAG programme has been expanded with gas from Tambar and Blane. Gas lift is used in some of the wells.

Transport:
The oil is transported by pipeline via Ekofisk to Teesside. All gas is re-injected into the reservoir in order to increase oil recovery.

Status:
Based on the positive effect the WAG program has on oil recovery, it has been expanded by drilling several additional wells. An agreement has been made to process the wellstream from Oselvar, and to buy the gas for injection in Ula from the end of 2011. In 2010, test production from the reservoir of Triassic age, underlying the main reservoir, was approved.





Urd

Blocks and production licences	Block 6608/10 - production licence 128, awarded 1986	
Discovered	2000	
Development approval	02.07.2004 by the Crown Prince Regent in Council	
On stream	08.11.2005	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	11.50 %
	Petoro AS	24.55 %
	Statoil Petroleum AS	63.95 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	8.7 million scm oil	4.7 million scm oil
	0.1 billion scm gas	
Production	**Estimated production in 2010:**	
	Oil: 10 000 barrels/day	
Investment	Total investment is expected to be NOK 5.7 billion (2010 values)	
	NOK 5.4 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Harstad	

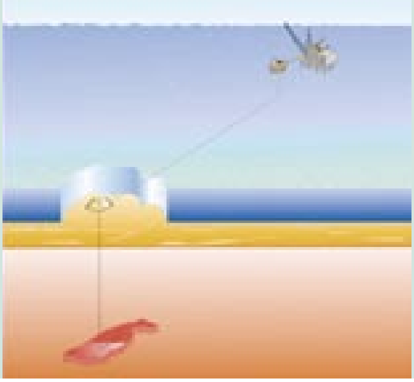
Development:
Urd is located northeast of Norne in the Norwegian Sea. The sea depth in the area is approximately 380 metres. The field comprises two oil deposits, 6608/10-6 Svale and 6608/10-8 Stær. Urd has been developed with subsea templates tied back to the Norne vessel. In April 2008, an amended PDO for Norne and Urd was approved. The plan comprises the discovery 6608/10-11 S Trost and a number of prospects in the area around Norne and Urd.

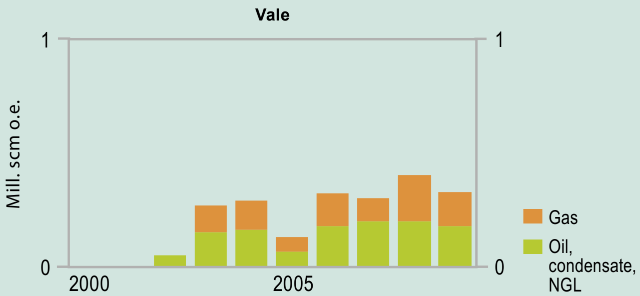
Reservoir:
The reservoirs consist of Lower to Middle Jurassic sandstones of the Åre, Tilje and Ile Formations at a depth of 1 800 - 2 300 metres.

Recovery strategy:
Urd is recovered by water injection. In addition, the wells are supplied with gas lift to be able to produce at low reservoir pressure and high water cut.

Transport:
The wellstream is processed on “Norne FPSO”, and oil is buoy-loaded together with oil from the Norne field. The gas is sent from Norne to Åsgard, and then exported via Åsgard Transport System to Kårstø.

Status:
Production performance has been lower than expected in 2009. This is a result of production being shut down for four months due to leakage and insufficient pressure support. Proven resources in the Melke Formation, overlying the Svale and Stær deposits, are presently not considered profitable for production.





Vale

Blocks and production licences	Block 25/4 - production licence 036, awarded 1971	
Discovered	1991	
Development approval	23.03.2001 by the Crown Prince Regent in Council	
On stream	31.05.2002	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	46.90 %
	Statoil Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	2.0 million scm oil	0.8 million scm oil
	2.1 billion scm gas	1.2 billion scm gas
Production	**Estimated production in 2010:**	
	Oil: 4 000 barrels/day, Gas: 0.19 billion scm	
Investment	Total investment is expected to be NOK 3.2 billion (2010 values)	
	NOK 3.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	

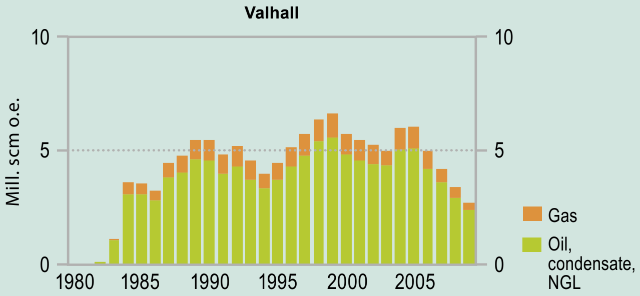
Development:
Vale is a gas and condensate field located 16 kilometres north of Heimdal in the middle part of the North Sea. The field has been developed with a subsea template tied back to Heimdal. The water depth in the area is approximately 115 metres.

Reservoir:
The reservoir consists of Middle Jurassic sandstones of the Brent Group. The reservoir depth is approximately 3 700 metres. The reservoir has low permeability.

Recovery strategy:
The field is recovered by pressure depletion.

Transport:
The wellstream from Vale goes to Heimdal for processing and export.

Status:
The wellstream from Vale has a high wax content, which creates challenges at Heimdal, and results in reduced production in periods.



Valhall

Blocks and production licences	Block 2/11 - production licence 033 B, awarded 2001	
	Block 2/8 - production licence 006 B, awarded 2000	
Discovered	1975	
Development approval	02.06.1977 by the Storting	
On stream	02.10.1982	
Operator	BP Norge AS	
Licensees	BP Norge AS	28.09 %
	Enterprise Oil Norge AS	28.09 %
	Hess Norge AS	28.09 %
	Total E&P Norge AS	15.72 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	144.2 million scm oil	43.0 million scm oil
	26.6 billion scm gas	6.7 billion scm gas
	5.4 million tonnes NGL	2.2 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 36 000 barrels/day, Gas: 0.38 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 91.6 billion (2010 values)	
	NOK 77.6 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

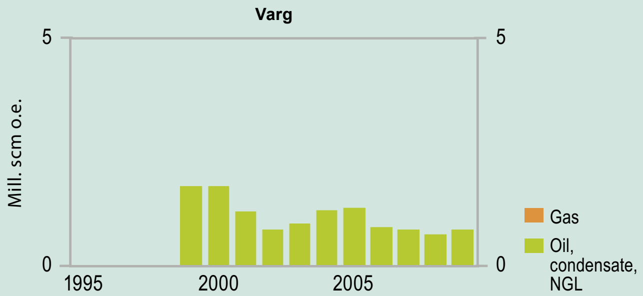
Development:
Valhall is an oil field located in the southern part of the North Sea. The sea depth in the area is about 70 metres. The field was originally developed with three facilities, for accommodation, drilling and production. In 1996, a wellhead facility (Valhall WP) with 19 slots for additional wells was installed. The four facilities are connected by bridges. A water injection facility was installed centrally on the field in the summer of 2003 and connected by bridge to Valhall WP. The drilling rig on this facility will also be used by Valhall WP. The flank development consists of two wellhead facilities positioned in the north and south of the field. The southern facility came on stream in 2003 and the northern facility came on stream in 2004. Valhall processes production from Hod, and delivers gas for gas lift in Hod. The PDO for Valhall WP was approved on 02.06.1995. The PDO for Valhall water injection was approved on 03.11.2000. The PDO for Valhall flank development was approved on 09.11.2001. A PDO for Valhall redevelopment was approved on 14.06.2007.

Reservoir:
The Valhall field produces from chalk in the Tor and Hod Formations of Late Cretaceous age. The reservoir depth is approximately 2 400 metres. The chalk in the Tor Formation is finegrained and soft, with pervasive fractures allowing oil and water to flow more easily.

Recovery strategy:
Recovery originally took place by pressure depletion with compaction drive. As a result of pressure depletion from production, compaction of the chalk has caused subsidence of the seabed, presently six metres at the central part of the field. Water injection in the centre of the field started in January 2004, the strategy being to expand water injection to new parts of the field for more pressure support and better displacement of the oil. Gas lift is also important to optimize production in most of the wells.

Transport:
Oil and NGL are routed via pipeline to Ekofisk for onward transport to Teesside. Gas is sent via pipeline to Norpipe for onward transport to Emden.

Status:
In 2009, a project was approved to establish gas lift in the wells on the flanks of the field. During the past year, less water has been injected than planned. Part of the reason for that is microbial corrosion and scaling in the injection wells. Production at Valhall was shut down for more than two months during 2009 for improvements. A new field centre with a processing plant and accommodation facilities is under construction, and will be finished in 2011. The jacket was installed on the field summer 2009. The new facility will be supplied with electric power from shore. In an effort to improve recovery, new production and injection wells will be drilled. Seismic data from permanent seismic cables on the seabed is utilised to identify new well targets with remaining oil in the reservoir.



Varg

Blocks and production licences	Block 15/12 - production licence 038, awarded 1975	
Discovered	1984	
Development approval	03.05.1996 by the King in Council	
On stream	22.12.1998	
Operator	Talisman Energy Norge AS	
Licensees	Det norske oljeselskap ASA	5.00 %
	Petoro AS	30.00 %
	Talisman Energy Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	16.5 million scm oil	4.5 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 15 000 barrels/day	
Investment	Total investment is expected to be NOK 10.7 billion (2010 values)	
	NOK 10.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

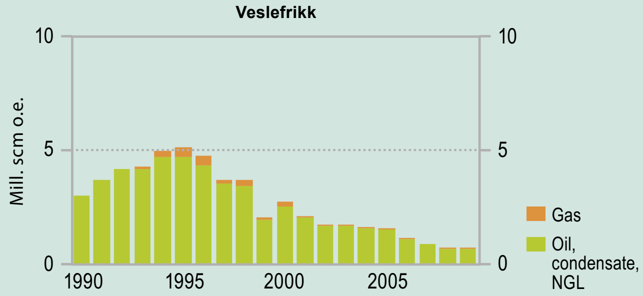
Development:
Varg is an oil field to the south of Sleipner Øst in the middle part of the North Sea. The sea depth in the area is 84 metres. The field has been developed with a production vessel, "Petrojarl Varg", with integrated oil storage, which is connected to the wellhead facility Varg A. The decommissioning plan for the field was approved in 2001. The plan then was to produce until summer 2002, but measures taken on the field have prolonged its lifetime.

Reservoir:
The reservoir is in Upper Jurassic sandstones at a depth of approximately 2 700 metres. The structure is segmented and includes several isolated substructures.

Recovery strategy:
Recovery takes place by pressure maintenance using water and gas injection. The smaller structures are produced by pressure depletion. All the wells are producing with gas lift.

Transport:
Oil is off-loaded from the production vessel onto tankers. All the gas is injected, but a solution for possible gas export in the future is being considered.

Status:
The operator is continuously evaluating means to increase recovery at Varg. Exploration well 15/12-20 S, drilled in 2008, proved additional reserves that are now being produced. The discovery 15/12-21 Grevling, proven in 2009, can be connected to Varg. Measures to optimise recovery are being considered, among others water alternating gas injection (WAG). New wells are being drilled, and several are planned for the coming years. The contract with "Petrojarl Varg" is extended, and the field is expected to produce until 2020 if the lifetime of the facilities can be extended.



Veslefrikk

Blocks and production licences	Block 30/3 - production licence 052, awarded 1979	
	Block 30/6 - production licence 053, awarded 1979	
Discovered	1981	
Development approval	02.06.1987 by the Storting	
On stream	26.12.1989	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	37.00 %
	RWE Dea Norge AS	13.50 %
	Statoil Petroleum AS	18.00 %
	Talisman Resources Norge AS	27.00 %
	Wintershall Norge ASA	4.50 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	55.0 million scm oil	4.9 million scm oil
	4.3 billion scm gas	2.2 billion scm gas
	1.6 million tonnes NGL	0.3 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 15 000 barrels/day	
Investment	Total investment is expected to be NOK 30.1 billion (2010 values)	
	NOK 25.0 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

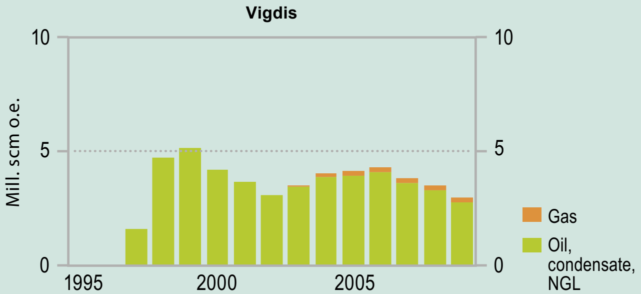
Development:
Veslefrikk is an oil field located about 30 kilometres north of Oseberg in the northern part of the North Sea. The sea depth is about 185 metres. The field is developed with two facilities, Veslefrikk A and Veslefrikk B. Veslefrikk A is a fixed steel wellhead facility with bridge connection to Veslefrikk B. Veslefrikk B is a semi-submersible facility for processing and accommodation. Veslefrikk B was upgraded in 1999 to handle condensate from the Huldra field. The PDO for the Statfjord Formation was approved on 11.06.1994. The PDO for the reservoirs in Upper Brent and I-areas was approved on 16.12.1994.

Reservoir:
The reservoirs consist of Jurassic sandstones of the Brent and Dunlin Groups and the Statfjord Formation. The main reservoir is in the Brent Group and contains about 80 per cent of the reserves. The reservoir depths are between 2 800 – 3 200 metres. The reservoir quality varies from moderate to excellent.

Recovery strategy:
Production takes place with pressure support from water injection, and water alternating gas injection (WAG) in the Brent and Dunlin reservoirs, and with gas circulation in the Statfjord Formation. Remotely controlled completions (DIACS) are used in three of the WAG wells.

Transport:
An oil pipeline is connected to the Oseberg Transport System (OTS) for transport to the Sture terminal. All gas is injected, but may be exported through the Statpipe system to Kårstø and Emden.

Status:
Veslefrikk is in tail production phase. A project, Veslefrikk 2020, is evaluating modification and upgrading of the facilities to prolong the lifetime of the field. Several methods to increase oil recovery are being evaluated. An appraisal well at the deposit 30/3-9 Canon was drilled early in 2009 in order to explore possible resources which may be tied to Veslefrikk. The discovery is being evaluated. A new well was drilled in 2009 for gas injection in the Statfjord Formation, and the first multi-branch well on Veslefrikk is being drilled.



Vigdis

Blocks and production licences	Block 34/7 - production licence 089, awarded 1984	
Discovered	1986	
Development approval	16.12.1994 by the King in Council	
On stream	28.01.1997	
Operator	Statoil Petroleum AS	
Licensees	ExxonMobil Exploration & Production Norway AS	10.50 %
	Idemitsu Petroleum Norge AS	9.60 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	2.80 %
	Statoil Petroleum AS	41.50 %
	Total E&P Norge AS	5.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	58.0 million scm oil	12.3 million scm oil
	1.6 billion scm gas	0.3 billion scm gas
	1.2 million tonnes NGL	0.4 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 41 000 barrels/day, Gas: 0.15 billion scm, NGL: 0.11 million tonnes	
Investment	Total investment is expected to be NOK 19.9 billion (2010 values)	
	NOK 18.8 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

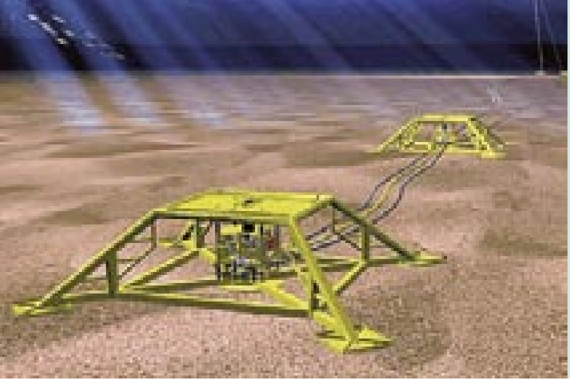
Development:
Vigdis is an oil field located between the Snorre and Gullfaks fields in the Tampen area in the northern part of the North Sea. The sea depth in the area is 280 metres. The field comprises several discoveries, and has been developed with subsea templates connected to Snorre A. The wellstream is routed to Snorre A through two flow lines. Injection water is transported by pipeline from Snorre A. Oil from Vigdis is processed in a dedicated processing module on Snorre A. The PDO for Vigdis Extension, including the discovery 34/7-23 S and adjoining deposits, was approved on 20.12.2002.

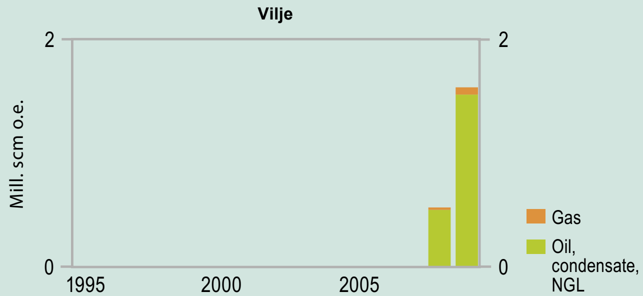
Reservoir:
The reservoir in the Vigdis Brent deposit consists of Middle Jurassic sandstones of the Brent Group, while the Vigdis Øst deposit has reservoirs in Lower Jurassic and Upper Triassic sandstones of the Statfjord Formation. The Borg Nordvest deposit has reservoir in Upper Jurassic intra-Draupne sandstones. The reservoirs are at a depth of 2 200 – 2 600 metres. The quality of the reservoirs is generally good.

Recovery strategy:
Production is based on partial pressure maintenance using water injection. Parts of the reservoirs are affected by the pressure blowdown of the Statfjord field, so water injection is used to counteract the effect.

Transport:
Stabilised oil from Vigdis is sent in a pipeline from Snorre A to Gullfaks A for storage and export. The gas from Vigdis is used for injection at Snorre.

Status:
The operator is evaluating means to improve recovery from Vigdis. A new production well was drilled in Borg Nordvest in 2009 and is producing. An exploration well, 34/7-34, was drilled northeast of Vigdis and proved new resources that can be tied to Vigdis. It has been decided to increase the water injection on Vigdis with water supplied from Statfjord C, but this has been delayed due to problems with the riser at Statfjord. Equipment for low pressure production is installed at Snorre A, and the capacity for produced water is upgraded. It is also being evaluated if gas alternating water injection (WAG) is feasible for Vigdis.





Vilje

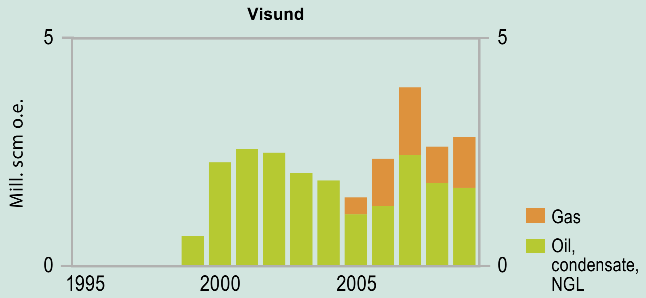
Blocks and production licences	Block 25/4 - production licence 036 D, awarded 2008	
Discovered	2003	
Development approval	18.03.2005 by the King in Council	
On stream	01.08.2008	
Operator	Statoil Petroleum AS	
Licensees	Marathon Petroleum Norge AS	46.90 %
	Statoil Petroleum AS	28.85 %
	Total E&P Norge AS	24.24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	8.3 million scm oil	6.2 million scm oil
Production	**Estimated production in 2010:**	
	Oil: 24 000 barrels/day	
Investment	Total investment is expected to be NOK 2.5 billion (2010 values)	
	NOK 2.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

Development:
Vilje is an oil field located in the middle part of the North Sea, about 20 kilometres northeast of Alvheim and just north of the Heimdal field. The sea depth in the area is approximately 120 metres. The field has been developed with two subsea wells connected to the production vessel “Alvheim FPSO”.

Reservoir:
The reservoir consists of sub-marine fan sandstones in the Heimdal Formation of Paleocene age and lies approximately 2 150 metres below sea level.

Recovery strategy:
The field is recovered by natural water drive from a large underlying aquifer.

Transport:
The wellstream is routed by pipeline to the production vessel at Alvheim, where the oil is buoy-loaded to tankers.



Visund

Blocks and production licences	Block 34/8 - production licence 120, awarded 1985	
Discovered	1986	
Development approval	29.03.1996 by the Storting	
On stream	21.04.1999	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	9.10 %
	Petoro AS	30.00 %
	Statoil Petroleum AS	53.20 %
	Total E&P Norge AS	7.70 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	31.3 million scm oil	11.6 million scm oil
	47.2 billion scm gas	42.4 billion scm gas
	5.9 million tonnes NGL	5.6 million tonnes NGL
Production	**Estimated production in 2010:**	
	Oil: 27 000 barrels/day, Gas: 1.02 billion scm, NGL: 0.13 million tonnes	
Investment	Total investment is expected to be NOK 34.1 billion (2010 values)	
	NOK 27.7 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Bergen	
Main supply base	Florø	

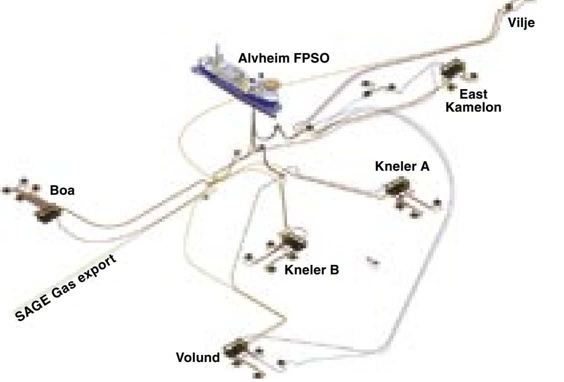
Development:
Visund is an oil field east of the Snorre field in the northern part of the North Sea. The development includes a semi-submersible integrated accommodation, drilling and processing steel facility (Visund A). The sea depth is about 335 metres at Visund A. The PDO for gas export was approved on 04.10.2002. The northern part of Visund was developed with a subsea template, about 10 kilometres north of Visund A, but has been shut down since 2006.

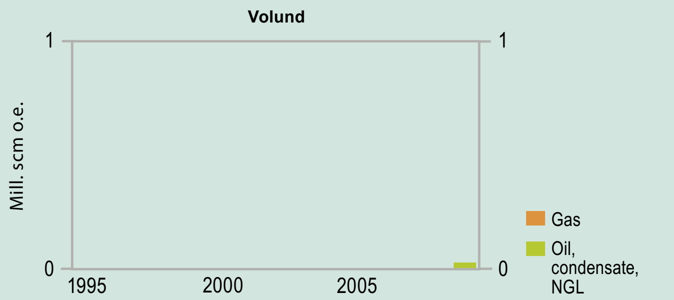
Reservoir:
Visund contains oil and gas in several tilted fault blocks with varying pressure and liquid systems. The reservoirs are in Middle Jurassic sandstones in the Brent Group, and Lower Jurassic and Upper Triassic sandstones in the Statfjord and Lunde Formations. The reservoirs lie at a depth of 2 900 - 3 000 metres.

Recovery strategy:
Oil production is driven by gas injection and water alternating gas injection (WAG). Produced water is also re-injected into one of the reservoirs. Limited export of produced gas was started autumn of 2005.

Transport:
The oil is sent by pipeline to Gullfaks A for storage and export with oil from Gullfaks. Gas is exported to the Kvitebjørn gas pipeline and on to Kollsnes, where the NGL is separated out and the dry gas further exported to the market.

Status:
A challenge for Visund is to maintain reservoir pressure to optimize oil recovery before gas export levels increase. In 2009 a water producer was drilled to increase water injection, and gas export has been reduced. The discovery 34/8-14 (Pan/Pandora), south of Visund, proven late in 2008, can be tied to Visund A or Gullfaks C. An exploration target east of Visund Nord was drilled in 2009, and proved additional resources which may be tied to a new development of Visund Nord.





Volund

Blocks and production licences	Block 24/9 - production licence 150, awarded 1988	
Discovered	1994	
Development approval	18.01.2007 by the King in Council	
On stream	10.09.2009	
Operator	Marathon Petroleum Norge AS	
Licensees	Lundin Norway AS	35.00 %
	Marathon Petroleum Norge AS	65.00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	7.2 million scm oil	7.2 million scm oil
	0.8 billion scm gas	0.8 billion scm gas
Production	**Estimated production in 2010:**	
	Oil: 16 000 barrels/day, Gas: 0.10 billion scm	
Investment	Total investment is expected to be NOK 3.5 billion (2010 values)	
	NOK 2.8 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

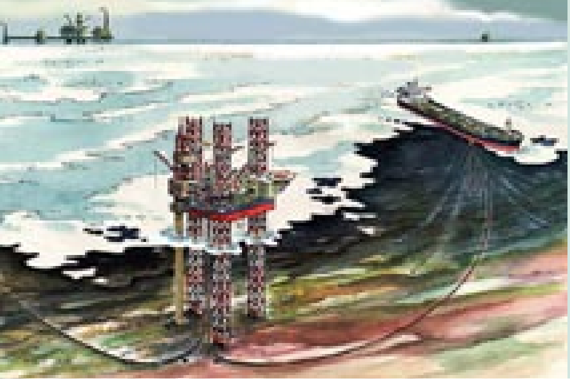
Development:
Volund is an oil field located about 10 kilometres south of Alvheim in the middle part of the North Sea. The sea depth in the area is 120 – 130 metres. The field is developed with three horisontal subsea wells connected to the production vessel “Alvheim FPSO”.

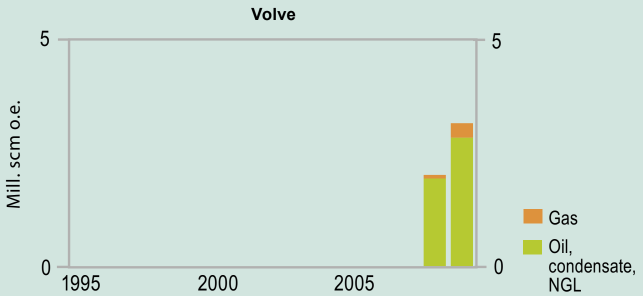
Reservoir:
The reservoir is in Paleocene sandstone intrusions in the Hermod Formation, which in Early Eocene time penetrated into the overlying Balder formation. The reservoir lies a depth of about 2 000 metres.

Recovery strategy:
Volund is produced by pressure suppport from water injection. The produced water for injection comes from Alvheim.

Transport:
The wellstream is routed by pipeline to Alvheim for buoy-loading. Associated gas is transported via Alvheim to St. Fergus in the United Kingdom.

Status:
Volund started production in September 2009 from a production well that was tested for 3 days. Afterwards, the field was shut down pending available production capacity at Alvheim. Volund is utilisied as a swing producer when capacity at Alvheim allows for it. Volund will be produced in this way until July 2010, when the field will be opened for regular production.





Volve

Blocks and production licences	Block 15/9 - production licence 046 BS, awarded 2006	
Discovered	1993	
Development approval	22.04.2005 by the Crown Prince Regent in Council	
On stream	12.02.2008	
Operator	Statoil Petroleum AS	
Licensees	Bayerngas Produksjon Norge AS	10.00 %
	ExxonMobil Exploration & Production Norway AS	30.40 %
	Statoil Petroleum AS	59.60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	8.8 million scm oil	4.3 million scm oil
	0.7 billion scm gas	0.3 billion scm gas
	0.1 million tonnes NGL	
	0.1 million scm condensate	
Production	**Estimated production in 2010:**	
	Oil: 28 000 barrels/day, Gas: 0.16 billion scm	
Investment	Total investment is expected to be NOK 3.4 billion (2010 values)	
	NOK 3.3 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stavanger	

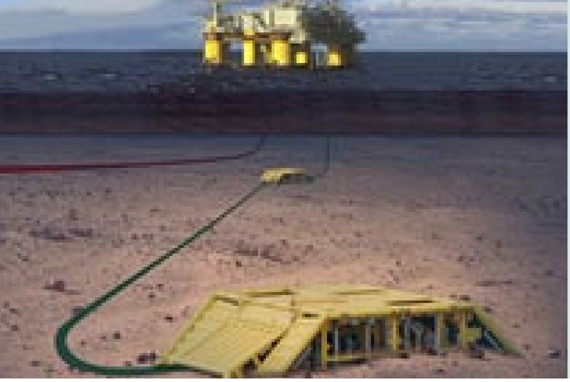
Development:
Volve is an oil field located in the middle part of the North Sea, approximately eight kilometres north of Sleipner Øst. The sea depth in the area is about 80 metres. The development concept is a jack-up processing and drilling facility and the vessel “Navion Saga”, for storing stabilised oil.

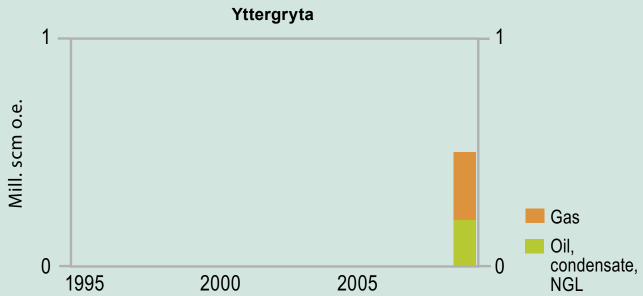
Reservoir:
The reservoir contains oil in a combined stratigraphic and structural trap in Jurassic sandstones of the Hugin Formation. The reservoir lies at a depth of 2 750 – 3 120 metres. The western part of the structure is heavily faulted and communication across the faults is uncertain.

Recovery strategy:
Volve is produced by water injection as the drive mechanism.

Transport:
The rich gas is transported to Sleipner A for further export. The oil is exported by tankers.

Status:
The prospects Volve Sør and Volve Vestflanke, which are included in the PDO, were drilled in 2008 and 2009 by extending new production wells. None of the wells proved oil. New drilling targets are being evaluated in order to establish a basis for a new drilling campaign.





Yttergryta

Blocks and production licences	Block 6507/11 - production licence 062, awarded 1981 Block 6507/11 - production licence 263 C, awarded 2008	
Discovered	2007	
Development approval	21.05.2008 by the King in Council	
On stream	05.01.2009	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS Petoro AS Statoil Petroleum AS Total E&P Norge AS	9.80 % 19.95 % 45.75 % 24.50 %
Recoverable reserves	**Original:** 0.2 million scm oil 1.8 billion scm gas 0.3 million tonnes NGL	**Remaining as of 31.12.2009** 0.1 million scm oil 1.5 billion scm gas 0.2 million tonnes NGL
Production	**Estimated production in 2010:** Oil: 1 000 barrels/day, Gas: 0.31 billion scm, NGL: 0.05 million tonnes	
Investment	Total investment is expected to be NOK 1.6 billion (2010 values) NOK 1.6 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	

Development:
The field is located in the Norwegian Sea, approximately 5 kilometres north of the Midgard deposit. The sea depth in the area is about 300 metres. It has been developed with a subsea template tied to Midgard, and one production well.

Reservoir:
The reservoir contains gas in Middle Jurassic sandstones of the Fangst Group and lies at a depth of 2 390 - 2 490 metres.

Recovery strategy:
The field is produced by pressure depletion. The reserve estimate has been increased based on production data. It is assumed that gas which flows from the northern reservoir segment to the main segment during production is the reason for the good production results.

Transport:
The gas is transported to the Midgard X-template and further to Åsgard B for processing. The gas from Yttergryta has a low CO_2 content, making it suitable for dilution of CO_2 in the Åsgard Transport System.

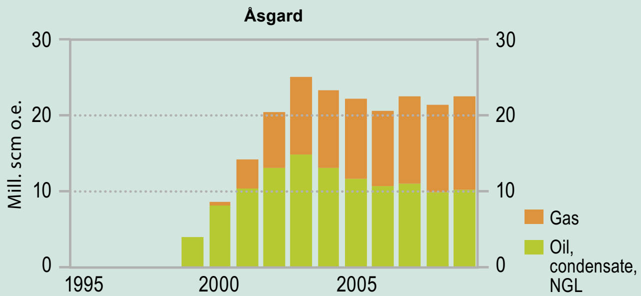
Status:
The field came on stream in January 2009. Increased reserves require a new contract with Åsgard for processing and transport.

Åsgard

Blocks and production licences	Block 6406/3 - production licence 094 B, awarded 2002	
	Block 6407/2 - production licence 074, awarded 1982	
	Block 6407/3 - production licence 237, awarded 1998	
	Block 6506/11 - production licence 134, awarded 1987	
	Block 6506/12 - production licence 094, awarded 1984	
	Block 6507/11 - production licence 062, awarded 1981	
Discovered	1981	
Development approval	14.06.1996 by the Storting	
On stream	19.05.1999	
Operator	Statoil Petroleum AS	
Licensees	Eni Norge AS	14.82 %
	ExxonMobil Exploration & Production Norway AS	7.24 %
	Petoro AS	35.69 %
	Statoil Petroleum AS	34.57 %
	Total E&P Norge AS	7.68 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2009**
	102.8 million scm oil	34.0 million scm oil
	184.7 billion scm gas	97.4 billion scm gas
	34.2 million tonnes NGL	18.9 million tonnes NGL
	16.1 million scm condensate	
Production	**Estimated production in 2010:**	
	Oil: 93 000 barrels/day, Gas: 11.82 billion scm, NGL: 2.13 million tonnes	
Investment	Total investment is expected to be NOK 96.1 billion (2010 values)	
	NOK 85.1 billion have been invested as of 31.12.2009 (2010 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

Development:
Åsgard is located centrally in the Norwegian Sea. The water depth in the area is 240 – 300 metres. Åsgard includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard. The field has been developed with subsea completed wells tied back to a production and storage vessel, "Åsgard A", which produces and stores oil, and a floating, semi-submersible facility, Åsgard B, for gas and condensate processing. The gas centre is connected to a storage vessel for condensate, Åsgard C. The Åsgard facilities are an important part of the Norwegian Sea infrastructure. In addition to processing Åsgard production, gas from Mikkel and Yttergryta is processed, and injection gas is delivered to Tyrihans. The Åsgard field has been developed in two phases. The liquid phase came on stream in 1999 and the gas export phase started on 01.10.2000.

Reservoir:
The Smørbukk deposit is a rotated fault block, bordered by faults in the west and north and structurally deeper areas to the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are of Jurassic age and contain gas, condensate and oil. The Smørbukk Sør deposit, with reservoir rocks in the Garn, Ile and Tilje Formations contains oil, gas and condensate. The Midgard deposit is divided into four structural segments with the main reservoir in the Garn and Ile Formations. The sandstone reservoirs lie at depths down to 4 850 metres. The reservoir quality varies between the formations, and there are large differences in porosity and permeability between the three deposits.



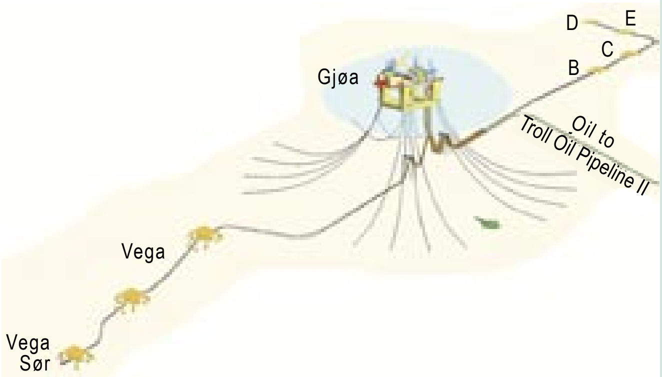
Recovery strategy:
Smørbukk Sør is produced by pressure support from gas injection. Smørbukk is produced partly by pressure depletion and partly by injection of excess gas from the field. Midgard is produced by pressure depletion. Studies are ongoing regarding converting gas injection wells to gas production wells at Smørbukk. This will maintain both gas injection in Smørukk Sør and gas export volume from Åsgard. Studies are also ongoing regarding the establishment of a gas compression facility at Midgard which is planned for start up in 2013-2014. This facility is needed to maintain the gas stream in the pipeline from Mikkel and Midgard to Åsgard B on a level that prevents creation of hydrates in the pipeline, which lead to production stop. A stable supply of low CO_2 gas from Mikkel and Midgard is also important for dilution of the high CO_2 gas from Kristin in the Åsgard Transport to Kårstø.

Transport:
Oil and condensate are temporarily stored at the field and shipped to land by tankers. The gas is exported through Åsgard Transport to Kårstø. The condensate from Åsgard is sold as oil (Halten Blend).

Status:
Most of the production wells have been drilled, and efforts are being made to increase recovery from the field, partly by drilling several sidetrack wells. Other efforts for increasing recovery from Åsgard A include for example upgrading the CO_2-removal facility at Åsgard B and extending the lifetime of Åsgard A. An appraisal well in 2009 proved oil and gas in a new segment northeast of Smørbukk. Work has begun to tie-in the deposit to Åsgard B, with planned production start in 2013. The Morvin field is being tied to Åsgard B, with planned production start in August 2010. There are other proven resources in the area with low CO_2 gas. Work is being done to realise these via Mikkel and Midgard to Åsgard B.

12

FIELDS UNDER DEVELOPMENT



Gjøa

Blocks and production licences	Block 35/9 - production licence 153, awarded 1988 Block 36/7 - production licence 153, awarded 1988	
Discovered	1989	
Development approval	14.06.2007 by the Storting	
Operator	Statoil Petroleum AS	
Licensees	A/S Norske Shell	12.00 %
	GDF SUEZ E&P Norge AS	30.00 %
	Petoro AS	30.00 %
	RWE Dea Norge AS	8.00 %
	Statoil Petroleum AS	20.00 %
Recoverable reserves	**Original:** 10.3 million scm oil 34.1 billion scm gas 5.9 million tonnes NGL	
Investment	Total investment is expected to be NOK 32.2 billion (2010 values) NOK 24.4 billion have been invested as of 31.12.2009 (2010 values)	

Development:
Gjøa is located about 40 kilometres north of the Fram field. The sea depth in the area is 360 metres. Statoil is operator for the development phase, while GDF SUEZ E&P Norge will take over as operator when production starts. The development comprises five subsea templates tied to a semi-submersible production and processing facility. The Gjøa facility will be supplied with power from land.

Reservoir:
The reservoir contains gas above a relatively thin oil zone in Jurassic sandstones in the Viking, Brent and Dunlin Groups. The field comprises several tilted fault segments with partly uncertain communication and varying reservoir quality. The reservoir depth is about 2 200 metres.

Recovery strategy:
The reservoir will be produced by pressure depletion.

Transport:
Stabilised oil will be exported in a new 55 kilometre long pipeline connected to Troll Oljerør II, for further transport to Mongstad. Rich gas will be exported in a new 130 kilometre long pipeline to the Far North Liquids and Associated Gas System (FLAGS) transport system on the UK continental shelf, for further transport to St. Fergus.

Status:
The Gjøa facility is now on location, and production is expected to start in autumn 2010.

Goliat

Blocks and production licences	Block 7122/7 - production licence 229, awarded 1997	
	Block 7122/8 - production licence 229, awarded 1997	
Discovered	2000	
Development approval	18.06.2009 by the Storting	
Operator	Eni Norge AS	
Licensees	Eni Norge AS	65.00 %
	Statoil Petroleum AS	35.00 %
Recoverable reserves	**Original:**	
	30.6 million scm oil	
	7.3 billion scm gas	
	0.3 million tonnes NGL	
Investment	Total investment is expected to be NOK 29.8 billion (2010 values)	
	NOK 0.9 billion have been invested as of 31.12.2009 (2010 values)	

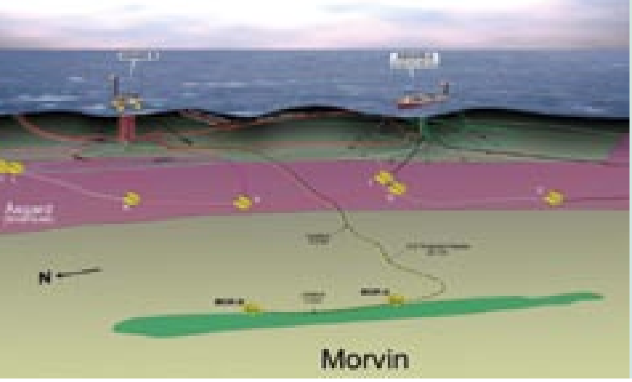
Development:
Goliat was discovered in 2000 and is located 50 kilometres southeast of Snøhvit in the Barents Sea. The sea depth in the area is 360 – 420 metres. Goliat will be developed with eight subsea templates with a total of 32 well slots. These will be tied to a circular, fixed floating production facility with an integrated storage and loading system.

Reservoir:
The reservoir comprises Triassic sandstones. There is oil and a thin gas cap in the Kapp Toscana Group and the Kobbe Formation. The reservoir lies at a depth of 1 100 metres, and the quality is variable.

Recovery strategy:
Goliat will be produced by water injection. Initially, associated gas will be injected, until a possible export solution of gas through the Snøhvit pipeline to Melkøya is in place.

Transport:
The oil will be loaded onto tankers and transported to the market. Possible export of gas to Melkøya is being evaluated.

Status:
Production is expected to start in 2013.



Morvin

Blocks and production licences	Block 6506/11 - production licence 134 B, awarded 2000 Block 6506/11 - production licence 134 C, awarded 2006
Discovered	2001
Development approval	25.04.2008 by the King in Council
Operator	Statoil Petroleum AS
Licensees	Eni Norge AS 30.00 % Statoil Petroleum AS 64.00 % Total E&P Norge AS 6.00 %
Recoverable reserves	**Original:** 9.3 million scm oil 3.2 billion scm gas 0.7 million tonnes NGL
Investment	Total investment is expected to be NOK 8.4 billion (2010 values) NOK 4.1 billion have been invested as of 31.12.2009 (2010 values)

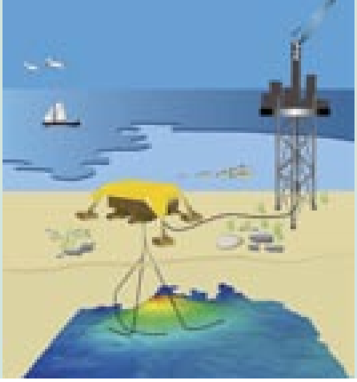
Development:
Morvin is located approximately 20 kilometres north of Kristin and 15 kilometres west of Åsgard. The sea depth in the area is about 350 metres. The field will be developed with two subsea templates tied to Åsgard B.

Reservoir:
The reservoir contains oil and gas in a rotated and tilted fault block at a depth of 4 500 - 4 700 metres, in Middle Jurassic sandstones in the Garn and Ile Formations. The reservoir in the Garn Formation is relatively homogenous, while the reservoir in the Ile Formation is more heterogeneous.

Recovery strategy:
Morvin will be produced by pressure depletion.

Transport:
The wellstream from Morvin will be transported by a 20 kilometre long pipeline to Åsgard B for processing and further transport.

Status:
Production is planned to start in autumn 2010.



Oselvar

Blocks and production licences	Block 1/2 - production licence 274 CS, awarded 2008	
	Block 1/3 - production licence 274, awarded 2002	
Discovered	1991	
Development approval	19.06.2009 by the King in Council	
Operator	DONG E&P Norge AS	
Licensees	Bayerngas Produksjon Norge AS	30.00 %
	DONG E&P Norge AS	55.00 %
	Norwegian Energy Company ASA	15.00 %
Recoverable reserves	**Original:**	
	4.0 million scm oil	
	4.6 billion scm gas	
Investment	Total investment is expected to be NOK 4.7 billion (2010 values)	
	NOK 0.6 billion have been invested as of 31.12.2009 (2010 values)	

Development:
Oselvar is located 21 kilometres southwest of Ula in the southern part of the North Sea. The sea depth in the area is about 70 metres. The development concept is a subsea template tied to Ula via pipelines.

Reservoir:
The reservoir lies at a depth of 2 900 – 3 250 metres in Paleocene sandstones belonging to the Forties Formation. The reservoir contains oil with a gas cap.

Recovery strategy:
Oselvar will be produced by natural pressure depletion via horizontal production wells.

Transport:
The wellstream will be transported by pipeline to Ula for processing. The gas will be used for injection in Ula for improved recovery, while the oil will be transported by pipelines to Ekofisk for further transport.

Status:
Production is planned to start at the end of 2011.

Skarv

Blocks and production licences	Block 6507/2 - production licence 262, awarded 2000 Block 6507/3 - production licence 159, awarded 1989 Block 6507/3 - production licence 212B, awarded 2002 Block 6507/5 - production licence 212, awarded 1996 Block 6507/6 - production licence 212, awarded 1996	
Discovered	1998	
Development approval	18.12.2007 by the Storting	
Operator	BP Norge AS	
Licensees	BP Norge AS	23.84 %
	E.ON Ruhrgas Norge AS	28.08 %
	PGNiG Norway AS	11.92 %
	Statoil Petroleum AS	36.16 %
Recoverable reserves	**Original:** 16.5 million scm oil 42.1 billion scm gas 5.5 million tonnes NGL	
Investment	Total investment is expected to be NOK 39.2 billion (2010 values) NOK 21.1 billion have been invested as of 31.12.2009 (2010 values)	

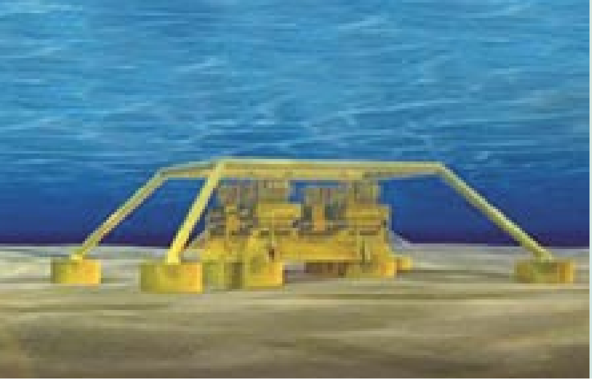
Development:
Skarv is located about 35 kilometres southwest of the Norne field in the northern part of the Norwegian Sea. The sea depth in the area is 350 - 450 metres. The development comprises the deposits 6507/5-1 Skarv and 6507/3-3 Idun. The deposit 6507/5-3 Snadd is part of Skarv, but is presently not included in the development. The development concept is a floating, production, storage and offloading vessel (FPSO) tied to five subsea templates.

Reservoir:
The reservoirs in Skarv contain gas and condensate in Middle and Lower Jurassic sandstones in the Garn, Ile and Tilje Formations. There is also an underlying oil zone in the Skarv deposit in the Garn and Tilje Formations. The Garn Formation has good reservoir quality, while the Tilje Formation has relatively poor quality. The reservoirs are divided into several fault segments and lie at a depth of 3 300 – 3 700 metres.

Recovery strategy:
In the Garn and Tilje Formations, re-injection of gas is planned for the first years in order to increase oil recovery.

Transport:
The oil will be buoy-loaded to tankers, while the gas will be exported in a new 80 kilometre long pipeline connected to the Åsgard Transport system.

Status:
The FPSO and templates are planned to be completed in the autumn of 2010. Drilling will start in 2010, and planned start of production is in 2011.



Vega

Blocks and production licences	Block 35/11 - production licence 248, awarded 1999	
	Block 35/8 - production licence 248, awarded 1999	
Discovered	1981	
Development approval	14.06.2007 by the Storting	
Operator	Statoil Petroleum AS	
Licensees	Petoro AS	40.00 %
	Statoil Petroleum AS	60.00 %
Recoverable reserves	**Original:**	
	1.7 million scm oil	
	9.4 billion scm gas	
	0.5 million tonnes NGL	
Investment	Total investment is expected to be NOK 5.0 billion (2010 values)	
	NOK 2.7 billion have been invested as of 31.12.2009 (2010 values)	

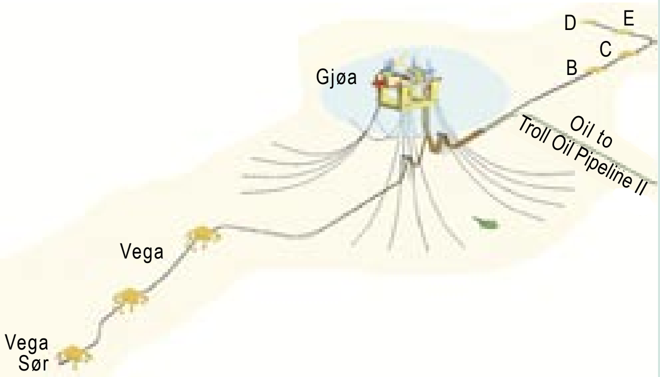
Development:
Vega is located directly north of the Fram field in the northern part of the North Sea. The sea depth in the area is about 370 metres. The field comprises two separate gas and condensate deposits, 35/8-1 and 35/8-2. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The field is being developed with two subsea templates tied to the processing facility at Gjøa.

Reservoir:
The reservoirs are in Middle Jurassic sandstones in the Brent Group, with high temperature and pressure, and relatively low permeability. The reservoir depth is about 3 500 metres.

Recovery strategy:
The field will be produced by pressure depletion.

Transport:
The wellstream will be sent by pipeline to Gjøa for processing. Oil and condensate will be transported from Gjøa in a new pipeline tied to Troll Oljerør II for further transport to Mongstad. The rich gas will be exported by a new pipeline to Far North Liquids and Associated Gas System (FLAGS) on the British continental shelf for further transport to St. Fergus.

Status:
Production is expected to start in autumn 2010.



Vega Sør

Blocks and production licences	Block 35/11 - production licence 090 C, awarded 2005	
Discovered	1987	
Development approval	14.06.2007 by the Storting	
Operator	Statoil Petroleum AS	
Licensees	Bayerngas Norge AS	25.00 %
	GDF SUEZ E&P Norge AS	15.00 %
	Idemitsu Petroleum Norge AS	15.00 %
	Statoil Petroleum AS	45.00 %
Recoverable reserves	**Original:**	
	3.6 million scm oil	
	8.7 billion scm gas	
	0.4 million tonnes NGL	
Investment	Total investment is expected to be NOK 3.1 billion (2010 values)	
	NOK 2.5 billion have been invested as of 31.12.2009 (2010 values)	

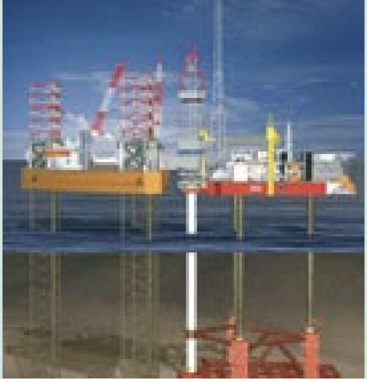
Development:
Vega Sør is located near the Fram field. The sea depth in the area is about 370 metres. A combined PDO for Vega and Vega Sør was approved by the authorities in June 2007. The development concept is a subsea template tied to Vega. A PDO exemption for the oil zone was approved autumn 2009.

Reservoir:
The reservoir contains gas and condensate with an oil zone in the upper part of the Brent Group of Middle Jurassic age. The reservoir depth is approximately 3 500 metres.

Recovery strategy:
The field will be produced by pressure depletion.

Transport:
The wellstream will be sent in a pipeline from Vega Sør via the subsea templates on Vega to Gjøa for processing. Oil and condensate will be transported from Gjøa in a new pipeline tied to Troll Oljerør II for further transport to Mongstad. The rich gas will be exported by a new pipeline to the Far North Liquids and Associated Gas System (FLAGS) on the British continental shelf for further transport to St. Fergus.

Status:
Production is expected to start in autumn 2010.



Yme

Blocks and production licences	Block 9/2 - production licence 316, awarded 2004	
	Block 9/5 - production licence 316, awarded 2004	
Discovered	1987	
Development approval	11.05.2007 by the King in Council	
Operator	Talisman Energy Norge AS	
Licensees	Lotos Exploration and Production Norge AS	20.00 %
	Talisman Energy Norge AS	70.00 %
	Wintershall Norge ASA	10.00 %
Recoverable reserves*	**Original:**	**Remaining as of 31.12.2009**
	19.3 million scm oil	11.4 million scm oil
Investment*	Total investment is expected to be NOK 11.5 billion (2010 values)	
	NOK 9.3 billion have been invested as of 31.12.2009 (2010 values)	

** Include original and new development*

Development:
Yme is located in the southeastern part of the North Sea. The sea depth is 77 – 93 metres. Yme is the first oil field on the Norwegian continental shelf to be redeveloped after having been shut down. The field was initially developed in 1995, by production licence 114 operated by Statoil. The production period lasted from 1996 to 2001, when operation of the field was considered to be unprofitable. New licensees in production licence 316, operated by Talisman, decided in 2006 to recover the remaining resources with a new jack-up production facility. The facility is placed above a storage tank for oil, located on the sea bed above the Gamma structure. The Beta structure is being developed with subsea wells.

Reservoir:
Yme contains two separate main structures, Gamma and Beta, comprising five deposits. The reservoir is in Middle Jurassic sandstones in the Sandnes Formation, at a depth of approximately 3 150 metres.

Recovery strategy:
Yme will mainly be produced by water injection. Excess gas can also be injected together with water in one well.

Transport:
The wellstream will be processed at the Yme facility, and the oil will be stored in the storage tank for export via buoy-loading to tankers. Excess gas is planned to be injected.

Status:
Start of production is expected in autumn 2010.

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FUTURE DEVELOPMENTS

This list does not comprise discoveries included in existing fields as of 31.12.09.

Development decided by the licensees

3/7-4 Trym	Production licence: 147, Operator: DONG E&P Norge AS
Resources	Gas: 4.2 billion scm, Condensate: 1.1 million scm

3/7-4 Trym was discovered in 1990 and is located three kilometres from the border to the Danish continental shelf. The sea depth in the area is approximately 65 metres. The discovery contains gas and condensate in Upper Jurassic and Middle Jurassic sandstones in the Sandnes and Bryne Formations. It lies on the same salt structure as the Danish field Lulita, at a depth of about 3 400 metres. The deposits are assumed to be separated by a fault zone on the Norwegian side of the border, but there may be pressure communication in the water zone. A PDO was submitted to the authorities 21.10.2008 and approved in March 2010. The development concept is a subsea facility tied to the Harald facility on the Danish side of the border. The wellstream will be processed on the Harald facility for further transport.

33/9-6 Delta	Production licence: 037 D, Operator: Wintershall Norge ASA
Resources	Oil: 0.1 million scm

33/9-6 Delta was discovered in 1976 and is located near the border to the British continental shelf between Murchison and Statfjord Nord. The reservoir is in Middle Jurassic sandstones in the Brent Group, at a depth of about 3 000 metres. An appraisal well has been drilled from the Murchison facility in the British sector, and the well is currently in test production.

Fields and discoveries in the planning phase

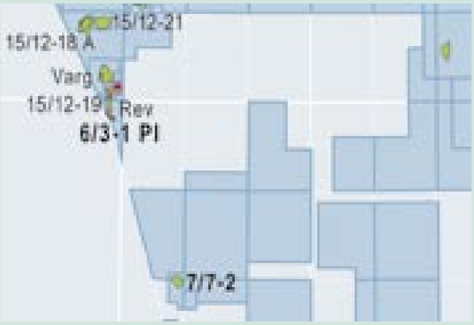
1/5-2 Flyndre	Production licence: 018 C, 297, Operator: Maersk Oil PL 018 C AS
Resources	Oil: 0.2 million scm

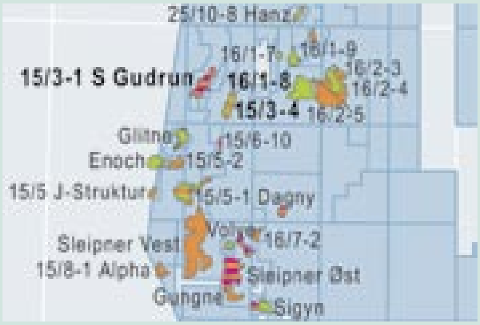
1/5-2 Flyndre was discovered in 1974 and is located at the border between the Norwegian and the British sectors. The sea depth is approximately 70 metres. The discovery contains oil and associated gas in Paleocene sandstones and Upper Cretaceous chalk. Four wells have been drilled on the discovery, one on the Norwegian side and three on the British side. The largest part of the resources is found in the Paleocene reservoir on the British continental shelf. According to plan, a PDO will be submitted to the authorities in 2010. The most likely development concept is a subsea template tied to facilities on the British side. Start of production is expected in 2012.

1/9-1 Tommeliten Alpha	Production licence: 044, Operator: ConocoPhillips Skandinavia AS
Resources	Oil: 7.0 million scm, Gas: 15.2 billion scm, NGL: 0.5 million tonnes

** Includes resources in RC5*

1/9-1 Tommeliten Alpha was discovered in 1977. The discovery is located about 20 kilometres southwest of the Ekofisk field, near the border to the British sector. The sea depth is approximately 80 metres. The reservoir contains gas and condensate in chalk at a depth of about 3 100 metres. Four appraisal wells have been drilled. The licensees are evaluating the development strategy and alternative development concepts, but it is probably many years before production start.





2/12-1 Freja	Production licence: 113, Operator: Hess Norge AS
Resources	Oil: 3.0 million scm, Gas: 0.8 billion scm, NGL: 0.1 million tonnes

2/12-1 Freja was discovered in 1987, close to the border between the Danish and Norwegian sectors. The sea depth in the area is 70 metres. The reservoir is in the Ula Formation of Late Jurassic age, at a depth of about 4 600 metres, and contains oil and associated gas. Freja lies in a geologically complex area between the structural units Fedagraben in the west and Gertrudgraben in the east. It is assumed that the reservoir is divided into separate fault blocks. Oil has also been proven in the nearby Gert deposit on the Danish side of the border. The development concept will be a subsea template connected to Valhall or to a facility in the Danish sector.

6/3-1 Pi	Production licence: 292, Operator: BG Norge AS
Resources	Oil: 1.0 million scm, Gas: 2.2 billion scm, NGL: 0.2 million tonnes, Condensate: 0.1 million scm

6/3-1 Pi was discovered in 1985, and delineated with well 15/12-19 in 2008. Pi is located about 12 kilometres south of the production vessel at Varg, and about 6 kilometres east of the Armada facility in the British sector. The reservoir contains oil and gas in Triassic and Middle Jurassic sandstones at a depth of about 3 000 metres. The development concept is a subsea template with 2 horizontal wells tied to the Armada facility. According to plan, the PDO is expected to be submitted to the authorities in the spring of 2010. Production can start in 2012.

7/7-2	Production licence: 148, Operator: Lundin Norway AS
Resources	Oil: 3.1 million scm

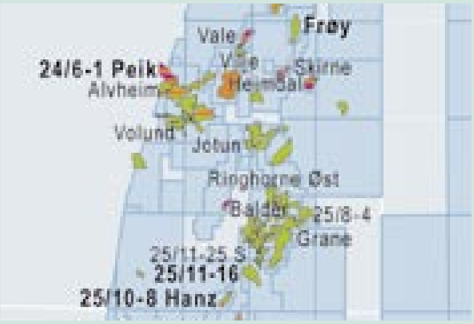
7/7-2 (Nemo) was discovered in 1992, and was delineated with additional wells drilled in 1993 and 2008. The discovery is located 43 kilometres northwest of the Ula field, and 22 kilometres northeast of the closest relevant facility in the British sector. The sea depth in the area is approximately 80 metres. The reservoir lies at a depth of approximately 3 300 metres in the Upper Jurassic Ula Formation. The development concept will most likely be a subsea development tied to a facility in the British sector.

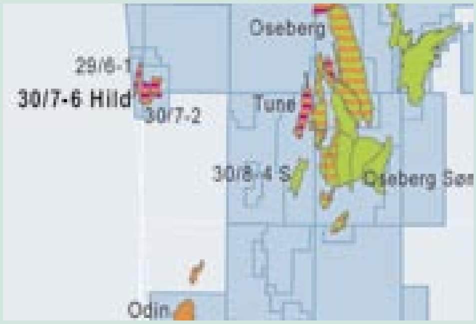
15/3-1 S Gudrun	Production licence: 025, Operator: Statoil Petroleum AS
Resources	Oil: 9.3 million scm, Gas: 7.8 billion scm, NGL: 1.1 million tonnes

15/3-1 S Gudrun was discovered in 1975 and is located about 40 kilometres north of the Sleipner fields. The sea depth is approximately 110 metres. The reservoirs contain oil and gas in sandstones in the Upper Jurassic Draupne Formation and gas in the Middle Jurassic Hugin Formation. The reservoirs lie at a depth of 4 000 - 4 760 metres. Gudrun will be developed with a processing facility tied to the Sleipner fields. The PDO was submitted to the authorities on 22.2.2010. Planned production start is in 2014.

15/3-4	Production licence: 025, 187 Operator: Statoil Petroleum AS
Resources	Oil: 2.0 million scm, Gas: 1.8 billion scm, NGL: 0.3 million tonnes

15/3-4 (Sigrun) was discovered in 1981 and is located about 10 kilometres southeast for Gudrun. The sea depth in the area is about 110 metres. The discovery contains oil in the Hugin Formation of Middle Jurassic age at a depth of about 3 800 metres. 15/3-4 Sigrun will be further evaluated in 2010. The planned development concept is a subsea template tied to Gudrun.





16/1-8	Production licence: 338, Operator: Lundin Norway AS
Resources	Oil: 18.8 million scm, Gas: 1.9 billion scm

** Resources in 16/1-12 (Luno Extension), RC7F, are not included*

16/1-8 (Luno) was discovered in 2007, about 30 kilometres south of Grane and Balder. Two appraisal wells, 16/1-10 and 16/1-13 were drilled in 2009 and 2010. The sea depth is about 100 metres. The discovery contains gas and oil in Jurassic and Upper Triassic sandstones and conglomerates. The reservoir lies at a depth of 1 900 – 1 990 metres. The licensees are considering a stand-alone development with a floating facility. According to plan, a PDO will be submitted to the authorities in 2011. Earliest start of production is probably in 2014.

24/6-1 Peik	Production licence: 088, Operator: Lundin Norway AS
Resources	Gas: 2.5 billion scm, Condensate: 0.7 million scm

24/6-1 Peik was discovered in 1985, and delineated by well 9/15a-1 drilled in the British sector in 1987. The discovery is located about 18 kilometres west of Heimdal and straddles the border to the British sector. The sea depth is about 120 metres. The reservoir contains Middle Jurassic sandstones in the Vestland Group. The reservoir lies at a depth of approximately 4 500 metres and contains gas and condensate under high pressure. The development concept is a subsea facility tied to Heimdal or to the Bruce field in the British sector.

Frøy	Production licence: 364, Operator: Det norske oljeselskap ASA
Resources	Oil: 8.7 million scm

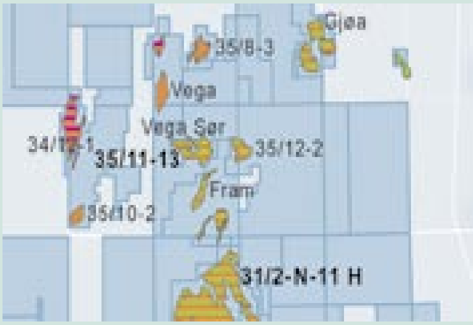
Frøy is an oilfield located in blocks 25/2 and 25/5, about 32 kilometres southeast of Frigg and 25 kilometres northeast of Heimdal. The sea depth in the area is about 120 metres. Frøy was originally part of production licences 026 and 102, which were awarded in 1976 and 1995. The field was discovered in 1987 and production started in May 1995, with Elf as the operator. When production was shut down in March 2001, a total of 5.6 million scm oil and 1.6 billion scm associated gas had been produced. Production licence 364 was awarded in January 2006 to Premier Oil and Det norske oljeselskap ASA, as operator. In September 2008, the operator submitted a PDO for re-development to the authorities. Subsequently, the licensees have withdrawn the PDO as a result of uncertainty related to profitability. The focus is now on reducing development costs, and a revised PDO may be submitted in 2010.

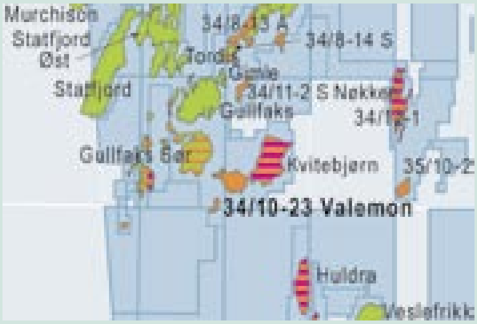
25/10-8 Hanz	Production licence: 028 B, Operator: Det norske oljeselskap ASA
Resources	Oil: 2.5 million scm, Gas: 0.3 billion scm, NGL: 0.1 million tonnes

25/10-8 Hanz was discovered in 1997 and is located between Sleipner and Grane. The reservoir is in Upper Jurassic sandstones in the Draupne Formation and lies at a depth of about 2 500 metres. The discovery will probably be developed as a subsea satellite tied to other discoveries in the area.

25/11-16	Production licence: 169, Operator: Statoil Petroleum AS
Resources	Oil: 12.6 million scm

25/11-16 was discovered in 1992, west of the Grane field, and includes the discovery 25/11-25 S made in 2008. The sea depth in the area is approximately 120 metres. The wells proved oil and associated gas in Paleocene to Lower Eocene sandstones in the Heimdal and Balder Formations at a depth of approximately 1 750 metres. The sandstones are deposited as sub-marine fans. The most likely development concept for both discoveries is subsea templates tied to Grane. According to plan, the PDO will be submitted to the authorities in 2011, with expected production start in 2014.





30/7-6 Hild	Production licence: 040, 043, Operator: Total E&P Norge AS
Resources	Oil: 4.0 million scm, Gas: 11.7 billion scm, NGL: 0.6 million tonnes, Condensate: 1.5 million scm

30/7-6 Hild was discovered in 1978, near the border to the British sector. The sea depth is 100–120 metres. The reservoir is structurally complex, and contains gas at high temperatures and pressure. There are three reservoirs in Middle Jurassic sandstones in the Brent Group at a depth of 3 700 - 4 400 metres. Oil has also been proven in a reservoir of Eocene age at approximately 1 750 metres. The licensees are evaluating different development concepts, and shall test the production characteristics through a well to ensure selection of the best possible development concept.

31/2-N-11 H	Production licence: 054, Operator: Statoil Petroleum AS
Resources	Oil: 0.4 million scm

The 31/2-N-11 H discovery was made in 2005 in the northern part of Troll Vest. The reservoir is in Middle Jurassic sandstones in the Brent Group underlying the reservoirs at Troll. The Brent reservoir lies at a depth of approximately 1 900 metres. The oil will be produced by a subsea facility connected to Troll C.

34/10-23 Valemon	Production licence: 050, 193, Operator: Statoil Petroleum AS
Resources	Oil: 7.2 million scm, Gas: 39.8 billion scm, NGL: 1.2 million tonnes

34/10-23 Valemon was discovered in 1985 and is located in blocks 34/11 and 34/10, west of the Kvitebjørn field. The sea depth is about 135 metres. Several appraisal wells are drilled on the discovery. The deposit has a complex structure with many faults. The reservoirs consist of Middle Jurassic sandstones in the Brent Group and Lower Jurassic sandstones in the Cook Formation. The reservoirs lie at a depth of approximately 4 000 metres, with high pressure and temperature. The PDO is expected to be submitted to the authorities in the second half of 2010. The discovery may be developed with a fixed facility, and earliest production start in 2014.

35/2-1	Production licence: 318, 318 C, Operator: Statoil Petroleum AS
Resources	Gas: 19.5 billion scm

35/2-1 (Peon) was discovered in 2005, and is located west of Florø, about 180 kilometres northeast of the Visund field. The sea depth is about 380 metres. The discovery contains methane. The reservoir consists of unconsolidated sandstones in the Nordland Group of Pleistocene age, and lies at a depth of only 580 metres below sea level. The shallow reservoir implies low pressure and well drilling challenges. The licensees drilled an appraisal well in 2009, and are now evaluating possible development concepts.

35/11-13	Production licence: 090 B, Operator: Statoil Petroleum AS
Resources	Oil: 6.2 million scm, Gas: 2.2 billion scm

35/11-13 (Astero) was discovered in 2005, and is located north of the Fram field. The sea depth is 360 metres. The reservoir contains oil with a gas cap in Upper Jurassic sandstones at a depth of approximately 3 100 metres. The appraisal well 35/11-14 S, drilled in the autumn of 2006, proved oil and gas in a new fault segment and supplied important additional information about the discovery. The development concept is expected to be subsea templates tied to Troll B or Gjøa.

6406/3-2 Trestakk	Production licence: 091, Operator: Statoil Petrolem AS
Resources	Oil: 7.7 million scm, Gas: 1.8 billion scm, NGL: 0.5 million tonnes

6406/3-2 Trestakk was discovered in 1984 and is located centrally on the Halten Terrace. The sea depth is about 300 metres. The reservoir contains Middle Jurassic sandstones in the Garn Formation at a depth of 3 900 - 4 000 metres. Reservoir quality is varying. Possible development concepts are a tie-in to Åsgard or Kristin, or a separate development.

6407/9-9	Production licence: 093, 158, Operator: A/S Norske Shell
Resources	Oil: 0.3 million scm, Gas: 1.4 billion scm

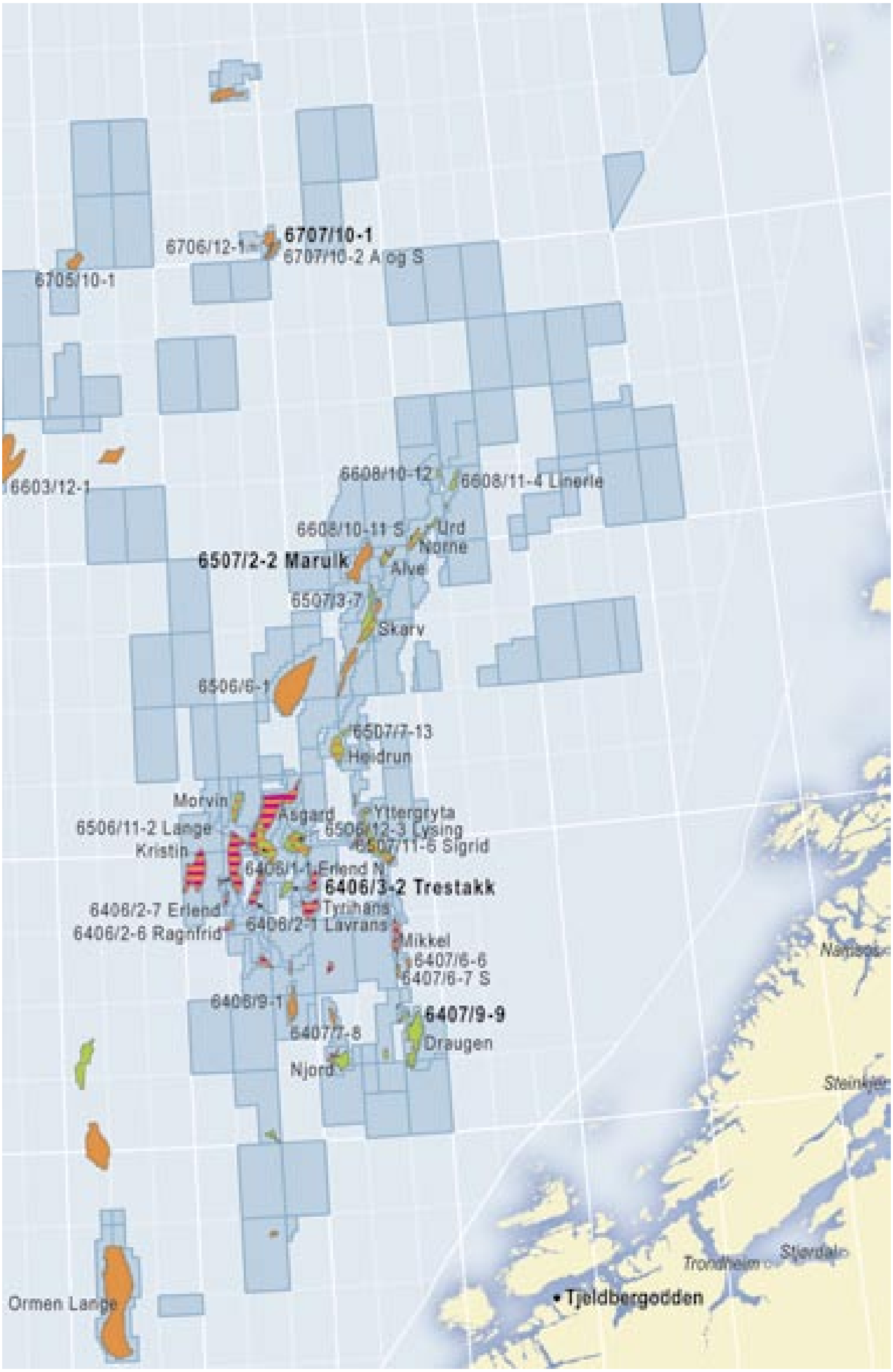
6407/9-9 (Hasselmus) was discovered in 1999, and is located about 7 kilometres northwest of Draugen. The reservoir contains oil and gas in the Ile and Ror Formations of Middle Jurassic age. The development concept is production from a well tied to the Draugen facility. The main purpose of the development of 6407/9-9 is to produce gas for power generation at Draugen. Production can start in 2013.

6507/2-2 Marulk	Production licence: 122, 122 D, 122 B, 122 C, Operator: Eni Norge AS
Resources	Oil: 0.6 million scm, Gas: 8.9 billion scm, NGL: 1.5 million tonnes

6507/2-2 Marulk was discovered in 1992 and is located about 30 kilometres southwest of Norne. The sea depth is about 370 metres. The reservoir contains gas and condensate in Cretaceous sandstones in the Lysing and Lange Formations at a depth of about 2 800 metres. Appraisal well 6507/2-4 was completed in 2008 and proved additional gas and condensate resources. The PDO is expected to be submitted to the authorities in 2010. The most likely development concept is a subsea facility tied to the Norne vessel for processing, and further transport of gas to Kårstø via existing pipelines. Earliest production start is 2012.

6707/10-1	Production licence: 218, Operator: Statoil Petroleum AS
Resources	Gas: 53.1 billion scm, Condensate: 0.9 million scm

6707/10-1 (Luva) was discovered in 1997, and is located about 320 kilometres west of Bodø. The sea depth in the area is about 1 270 metres. The reservoir contains gas in Cretaceous sandstones in the Nise Formation at a depth of about 3 000 metres. Two wells drilled nearby in 2008, 6707/10-2 S and 6706/12-1, proved more gas resources which can be tied to a joint development. A new floating field centre may be relevant, based on the size of the discoveries and the distance to other fields, but the development depends on solutions for gas transportation from the Norwegian Sea. It is therefore relevant to co-ordinate development and transportation plans with other discoveries, and possible new discoveries, in the Norwegian Sea. The great sea depth represents technical challenges regarding selection of development solutions.


6707/10-1
6706/12-1
6707/10-2 A og S
6705/10-1
6603/12-1
6608/10-12
6608/11-4 Linerle
6608/10-11 S
Urd
Norne
6507/2-2 Marulk
Alve
6507/3-7
Skarv
6506/6-1
6507/7-13
Heidrun
Morvin
Åsgard
Yttergryta
6506/11-2 Lange
6506/12-3 Lysing
Kristin
6507/11-6 Sigrid
6406/1-1 Erlend N
6406/3-2 Trestakk
6406/2-7 Erlend
Tyrihans
6406/2-6 Ragnfrid
6406/2-1 Lavrans
Mikkel
6407/6-6
6407/6-7 S
6406/9-1
6407/9-9
6407/7-8
Draugen
Njord
Namsos
Steinkjer
Trondheim
Stjørdal
Tjeldbergodden
Ormen Lange

14

FIELDS WHERE PRODUCTION HAS CEASED

The fields in this summary are not in production as of 31 December 2009. However, there are re-development plans for some of these fields. Yme is being re-developed, see chapter 12, Fields under development. Frøy is also described in chapter 13; Future developments.

Albuskjell

Block	1/6 and 2/4
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 7.4 million scm, Gas: 15.6 billion scm, NGL: 1.0 million tonnes

Status: The authorities decided 21.12.2001 that the facilities should be removed by 31.12.2013, and disposed of on land. Final disposal is ongoing.

Cod

Block	7/11
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 2.9 million scm, Gas: 7.3 billion scm, NGL: 0.5 million tonnes

Status: The authorities decided 21.12.2001 that the facilities should be removed by 31.12.2013, and disposed of on land. Final disposal is ongoing.

Edda

Block	2/7
Development approval	25.04.1975
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 4.8 million scm, Gas: 2.0 billion scm, NGL: 0.2 million tonnes

Status: The authorities decided 21.12.2001 that the facilities should be removed by 31.12.2013, and disposed of on land. Final disposal is ongoing.

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 26 September 2003, and in the Storting White Paper No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Operator at time of cessation	Total E&P Norge AS
Total production over field lifetime	Gas: 116.2 billion scm, Condensate: 0.5 million scm

Status: The facilities have been disposed of according to agreement, and the concrete jackets have been left behind at the site.

Frøy

Block	25/2 og 25/5
Development approval	18.05.1992
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 29 May 2001, and in the Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Operator at time of cessation	TotalFinaElf Exploration AS
Total production over field lifetime	Oil: 5.6 million scm, Gas: 1.6 billion scm, Condensate: 0.1 million scm

Status: The acreage was re-awarded in 2006 as production licence 364. The present operator is Det norske oljeselskap ASA. Frøy is also described in chapter 13, Future developments.

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999–2000) and Storting White Paper No. 47 (1999–2000)
On stream	13.05.1994
Production ceased	25.03.1999
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Oil: 1.3 million scm, Gas: 2.2 billion scm

Status: The acreage was re-awarded in 2006 as production licence 362. The present operator is Statoil Petroleum AS.

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/ decommissioning	Storting Proposition No. 15 (1996–1997) and Storting White Paper No. 47 (1999–2000)
On stream	01.01.1993
Production ceased	04.11.1993
Operator at time of cessation	Norsk Hydro Produksjon AS
Total production over field lifetime	Oil: 0.4 million scm, Gas: 0.1 billion scm

Status: The acreage was re-awarded in 2003 as production licence 301. The present operator is Lundin Norway AS. During 2010, an evaluation will be made whether an appraisal well will be drilled on the field in the future.

Nordøst Frigg

Block	25/1 og 30/10
Development approval	12.09.1980
Cessation plan/ decommissioning	Storting Proposition No. 36 (1994–1995)
On stream	01.12.1983
Production ceased	08.05.1993
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 11.6 billion scm, Condensate: 0.1 million scm

Status: The acreage was re-awarded in 2007 as production licence 415, but was relinquished in 2009.

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/ decommissioning	Storting Proposition No. 50 (1995–1996) and Storting White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Operator at time of cessation	Esso Exploration and Production Norway A/S
Total production over field lifetime	Gas: 27.3 billion scm, Condensate: 0.2 million scm

Status: The acreage was re-awarded in 2007 as production licence 415, but was relinquished in 2009.

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999-2000) and Storting White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
Operator at time of cessation	Den norske stats oljeselskap a.s.
Total production over field lifetime	Oil: 3.9 million scm, Gas: 9.7 billion scm, NGL: 0.5 million tonnes

Status: There are no specific plans to recover the remaining resources.

Vest Ekofisk

Block	2/4
Development approval	04.05.1973
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 21 December 2001 and in the Storting White Paper No. 47 (1999–2000)
On stream	31.05.1977
Production ceased	25.08.1998
Operator at time of cessation	Phillips Petroleum Company Norway
Total production over field lifetime	Oil: 12.2 million scm, Gas: 26.0 billion scm, NGL: 1.4 million tonnes

Status: The authorities decided 21.12.2001 that the facilities should be removed by 31.12.2013, and disposed of on land. Final disposal is ongoing.

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/ decommissioning	Storting Proposition No. 8 (1998–1999) and Storting White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Operator at time of cessation	Elf Petroleum Norge AS
Total production over field lifetime	Gas: 9.2 billion scm, Condensate: 0.1 million scm

Status: No activity

15

PIPELINES AND ONSHORE FACILITIES

Figure 15.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

The transport capacities are based on standard assumptions for pressure and gas energy content, maintenance downtime and operational flexibility.

Gassled pipelines

Operator: Gassco AS
Licensees:

Petoro AS[1]	38.459 %
Statoil Petroleum AS	32.102 %
Total E&P Norge AS	7.783 %
ExxonMobil Exploration and Production Norway AS	9.428 %
A/S Norske Shell	5.319 %
Norsea Gas AS	2.726 %
ConocoPhillips Skandinavia AS	1.996 %
Eni Norge AS	1.525 %
DONG E&P Norge AS	0.662 %

[1] Petoro AS is the licensee for the State's Direct Financial Interest (SDFI). Petoro's participating interest in Gassled will be increased by approximately 8 per cent, taking effect as of 1 January 2011. The other parties' participating interests will also be adjusted, taking effect from the same date.

In the spring of 2001, the Government asked the relevant companies to establish a unified ownership structure for gas export. Gassled represents the merger of nine gas transport facilities into a single partnership. The Gassled ownership agreement was signed on 20 December 2002, and came into effect on 1 January 2003. Gassled's licence runs to 2028.

Gassled includes: Europipe I, Europipe II, Franpipe, Norpipe, Oseberg Gas Transport, Statpipe, Tampen Link, Vesterled, Zeepipe, Åsgard Transport, Langeled, Norne Gas Transport System, Kvitebjørn Gas pipeline, Kollsnes gas processing plant and Kårstø gas and condensate processing plant. The receiving terminals for Norwegian gas in Germany, Belgium, France and the United Kingdom are, entirely or partly, owned by Gassled. Gassled is organised into various zones for access and tariffs. Gassco coordinates and controls the flow of gas through a network of pipelines about 7 800 kilometres long, and handles all transport of Norwegian gas to the markets.

Europipe I

This 40-inch pipeline starts at the Draupner E riser facility and runs for 660 kilometres, ending at Emden in Germany. Europipe I came into operation in 1995. The pipeline has a diameter of 40 inches, is 620 kilometres long and has a capacity of about 45 - 54 million scm per day, depending on operating mode. The pipeline has been built for an operating life of 50 years and total investment at start-up was approximately NOK 23.3 billion (2010 value). In addition to the pipeline, investments also include the terminal in Dornum and the Europipe Metering Station (EMS) in Emden.

(Agreement between Norway and Germany concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to the Federal Republic of Germany. (The Europipe Agreement), ref. Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993).)

Europipe II

This 42-inch pipeline runs for 658 kilometres from Kårstø to Dornum in Germany, Europipe Receiving Facilities (ERF), and became operational in 1999. With a capacity of about 74 million scm per day, Europipe II has been built for an operating life of 50 years. Total investment at start-up was approximately NOK 10.5 billion (2010 value).

(Supplementary agreement of 19 May 1999 to the Europipe agreement (see Storting Proposition No. 60 (1992-1993) and Recommendation No. 164 (1992–1993)) concerning the transmission of gas from Norway through a new pipeline (Europipe II) to Germany, ratified in accordance with Royal Decree of 14 September 2001).

Franpipe

This 42-inch gas pipeline runs for 840 kilometres from the Draupner E riser facility in the North Sea to a receiving terminal at Dunkerque in France. The Gassled partnership owns 65 per cent of the terminal, while GDF SUEZ owns 35 per cent. The pipeline became operational in 1998. Franpipe has a capacity of about 54 million scm per day. It has been built for an operating life of 50 years. The total investment at start-up was approximately NOK 10.9 billion (2010 value).

(Agreement between Norway and France concerning the transmission of gas from the Norwegian continental shelf and other areas, through a pipeline, to France, ref. Storting Proposition No. 44 (1996–1997) and Recommendation No. 172 (1996–1997).)

Norpipe Gas pipeline

This 36-inch pipeline starts at Ekofisk and runs for 440 kilometres to the Norsea Gas terminal in Emden, Germany. Also owned by Gassled, the Emden terminal cleans and meters the gas prior to onward distribution. The line became operational in 1977. Two riser facilities, H7 and B11, each with three compressors, are positioned on the German continental shelf. In 2007 a bypass was installed at H7, and H7 has now been shut down. The transport capacity is approximately 32 million scm per day without using the compressor capacity on the B11 riser facility. Capacity will increase to 44 million scm per day if the B11 compressors are used. Norpipe has been built for an operating life of at least 30 years. The application for extension of the lifetime of both Norpipe Gas pipeline and B11 is approved and are valid until the end of the licence period in 2028. Total investment at start-up was approximately NOK 28.9 billion (2010 value).

(Agreement between Norway and Germany concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to Germany, ref. Storting Proposition No. 88 (1973-1974) and Recommendation No. 250 (1973-1974).)

Oseberg Gas Transport (OGT)

This 36-inch line starts at Oseberg and runs for roughly 109 kilometres to the riser facility at Heimdal (HRP). The pipeline became operational in 2000 and has a capacity of approximately 40 million scm per day. OGT has been built for an operating life of 50 years, and total investment at start-up was approximately NOK 2.2 billion (2010 value).

Statpipe

Statpipe is an 880 kilometre long pipeline system with a riser facility, Draupner S/E, and a gas processing plant at Kårstø. The system became operational in 1985. Statpipe Rich Gas, with a diameter of 30 inches, starts at Statfjord and runs for 308 kilometres to Kårstø, with a capacity of about 24 million scm per day. Statpipe Dry Gas has three components. One of these comprises a 28-inch pipeline running for about 228 kilometres from Kårstø to the Draupner S riser facility, with a capacity of roughly 20 million scm per day, depending on operating mode. The second component is a 36-inch pipeline running for about 155 kilometres from the the main facility at Heimdal (HMP) to Draupner S, with a capacity of about 30 million scm per day. The third is a 36-inch pipeline running for roughly 203 kilometres from Draupner S to Ekofisk-Y, with a capacity of about 30 million scm per day. The Heimdal-Draupner S and Kårstø-Draupner S pipelines can also be used for reversed flow. Total investment at start-up was approximately NOK 49.9 billion (2010 value).

Tampen Link

The pipeline Tampen Link starts at the Statfjord field and ends at the FLAGS pipeline, 1.4 kilometres south of the Brent Alpha facility. About 15.5 kilometres of the pipeline lies on the British side of the border. Tampen Link became operational, and was included in Gassled, in 2007. The pipeline has a diametre of 32 inches, runs for 23 kilometres and has a capacity of approximately 25 million scm per day. The capacity is dependent upon inlet conditions at the connection points in the Statfjord area. Total investment at start-up was approximately NOK 2.2 billion (2010 value). The investments include, in addition to the pipeline, necessary modifications on Statfjord B. Tampen Link has been built for an operating life of 30 years. (See plan for installation and operation referred to in St.prp. No. 53 (2004-2005).

Vesterled

This 32-inch pipeline runs for about 360 kilometres from the Heimdal riser facility (HRP) to the receiving terminal at St. Fergus in the UK and became operational in 1978. It has a capacity of approximately 38.0 million scm per day. Total investment in Vesterled at start-up was approximately NOK 35.3 billion (2010 value). In addition to the pipeline, this total investment includes investments associated with construction of the St. Fergus terminal.

(Agreement between Norway and the UK concerning amendments to the Frigg treaty of 10 May 1976. Referred to in St.prp. No. 73 (1998–1999) and Recommendation No. 219 (1998–1999)).

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 813 kilometres from Sleipner (SLR) to the receiving terminal in Zeebrugge, Belgium. The terminal in Zeebrugge belongs to a separate partnership, with the Gassled partners holding 49 per cent and the Belgian Fluxys company holding 51 per cent. Zeepipe I became operational in 1993 and has a capacity of roughly 42 million scm per day. Zeepipe I also includes a 30-inch pipeline between Sleipner (SLR) and Draupner S.

Zeepipe II A starts at the Kollsnes gas processing plant and ends at the Sleipner riser facility. This pipeline became operational in 1996. Zeepipe II A is a 40-inch pipeline which is 299 kilometres long and has a capacity of 72 million scm per day.

Zeepipe II B starts at the Kollsnes gas processing plant and ends at Draupner E. The pipeline became operational in 1997. Zeepipe II B has a 40-inch diameter, runs for about 301 kilometres and has a capacity of 71 million scm per day. The Zeepipe system has been built for an operating life of 50 years. Total investment at start-up is approximately NOK 26.3 billion (2010 value).

(Agreement between Norway and Belgium concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to Belgium, ref. Storting Proposition No. 148 (1987–1988) and Recommendation No. 21 (1988–1989).)

Åsgard Transport

This 42-inch pipeline runs for about 707 kilometres from the Åsgard field to Kårstø. It became operational in 2000, with a capacity of approximately 69 million scm per day. Åsgard Transport is built for an operating life of 50 years. Total investment at start-up was approximately NOK 11.5 billion (2010 value).

Langeled

The Langeled gas transport system runs from the onshore facilities for Ormen Lange at Nyhamna, via a tie-in point at the Sleipner riser facility to a new receiving terminal at Easington on the eastern coast of the UK. The system comprises a 42-inch pipeline from Nyhamna to the Sleipner riser (northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity is approximately 80 million scm per day in the northern leg and about 70 million scm per day in the southern leg.

The system has an overall length of roughly 1 200 kilometres. The southern pipeline became operational in October 2006, with the northern pipeline following in 2007. Norsk Hydro was the operator for the development phase of the southern leg, while Gassco AS is the operator for the development phase of the northern leg and the operating phase of the whole transport system.
Langeled was included in Gassled in the autumn of 2006. Total investment at start-up was approximately NOK 18.6 billion (2010 values).

Norne Gas Transport System (NGTS)

The 16-inch pipeline runs for about 126 kilometres and connects the Norne field to Åsgard Transport. The pipeline has a capacity of approximately 3.6 billion scm per year. The Norne Gas Transport System has been built for an operating life of 50 years. The pipeline became operational in 2001. Total investment at start-up was approximately NOK 1.3 billion (2010 values). Norne Gas Transport System was included in Gassled as of 01.01.2009.

Kvitebjørn Gas Pipeline

The 30 inch pipeline runs for about 147 kilometres and transports rich gas from Kvitebjørn and Visund to Kollsnes. The pipeline has a capacity of approximately 26.5 million scm per day and became operational in 2004, at the same time as the Kvitebjørn field. Total investment at start-up was approximately NOK 954 million 2002-values. The pipeline was included in Gassled in the spring of 2009.

Kollsnes gas processing plant

The gas processing plant at Kollsnes forms part of Gassled. Wellstreams are separated at Kollsnes into gas and condensate. The gas is dried and compressed before being sent to the Continent via two pipelines to Sleipner and Draupner.

Kollsnes also delivers a small amount of gas to the LNG-plant at the Kollsnes Industrial Park. Following a stabilisation process, the condensate is sent on to the Vestprosess plant at Mongstad. The Kollsnes plant was upgraded in 2004 with an NGL extraction plant for processing gas from Kvitebjørn and Visund. After the upgrade, the capacity is 143 million scm dry gas per day and 9 780 scm condensate per day. In order to ensure that the plant can deliver 143 million scm dry gas per day, a new export compressor was put into operation from 2006.

Kårstø gas and condensate processing plant

Rich gas and unstabilised condensate are transported to Kårstø. At the processing plant, these products are separated to dry gas and to six different liquid products. In addition to methane the rich gas contains the components ethane, propane, normal butane, iso-butane and naphtha. The products are separated and stored for shipping. The dry gas, which largely contains methane and ethane, is transported by two pipelines from Kårstø, Europipe II to Germany and Statpipe to Draupner. The Kårstø condensate facility receives unstabilised condensate from the Sleipner fields. The condensate is stabilised by separating out the lightest components. Ethane, iso-butane and normal butane are stored in refrigerated tanks, while naphtha and condensate are held in tanks at ambient temperature. Propane is stored in large refrigerated rock caverns. These products are exported from Kårstø as liquid by ship.

The processing facilities at Kårstø include, among others, four extraction/fractionation lines for methane, ethane, propane, butanes and naphtha, and a fractionation line for stabilising condensate. The condensate plant has a capacity of approximately 5.5 million tonnes of unstabilised condensate per year. After the last expansion, the KEP-2005 project, the capacity for recovering ethane at Kårstø has increased to 950 000 tonnes per year. At the same time, the gas processing facility was upgraded to handle 88 million scm rich gas per day.

Other pipelines

Draugen Gas Export

Operator	A/S Norske Shell	
Licensees	Petoro AS	47.88 %
	BP Norge AS	18.36 %
	A/S Norske Shell	26.20 %
	Chevron Norge AS	7.56 %
Investment	Total investment at start-up was approximately NOK 1.2 billion (2010 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 2 billion scm per year	

This 16-inch pipeline links the Draugen field to Åsgard Transport, and provides opportunities for possible tie-ins of other fields in the area. The pipeline is 78 kilometres long and commenced operation in 2000.

Gjøa Gas Export

Operator	Statoil Petroleum AS
Licencees	As for the Gjøa field
Investment	Total investments at start-up was approximately NOK 1.9 billion (2010 value)
Operating lifetime	The technical operating lifetime is 30 years
Capacity	Approximately 6.1 billion scm per year

The pipeline connects the Gjøa and Vega fields to the Far North Liquids and Associated Gas System (FLAGS) transport system. The pipeline is 130 kilometres long, with a diameter of 28 inches. Start-up is planned in 2010.

Grane Gas Pipeline

Operator	Statoil Petroleum AS
Licencees	As for the Grane field
Investment	Total investment at start-up was approximately NOK 0.3 billion (2010 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Approximately 3.6 billion scm per year

The pipeline commenced operation in 2003. Gas injection is required in order to produce the oil from the Grane field. This gas is transported to the field through the Grane Gas Pipeline. The 50 kilometres long pipeline runs from the Heimdal riser facility to Grane. The diameter of the pipeline is 18 inches.

Grane Oil Pipeline

Operator	Statoil Petroleum AS	
Licensees	Petoro AS	42.06 %
	ExxonMobil Exploration and Production Norway AS	28.22 %
	Statoil Petroleum AS	23.54 %
	ConocoPhillips Skandinavia AS	6.17 %
Investment	Total investment at start-up was approximately NOK 1.7 billion (2010 value)	
Operating lifetime	The technical operating lifetime is 30 years	
Capacity	34 000 scm oil per day	

This pipeline became operational at the same time as the Grane field, in 2003. The pipeline links the Grane field to the Sture terminal. It is 220 kilometres long and has a diameter of 29 inches.

Haltenpipe

Operator	Gassco AS	
Licensees	Petoro AS	57.81 %
	Statoil Petroleum AS	19.06 %
	ConocoPhillips Skandinavia AS	18.13 %
	Eni Norge AS	5.00 %
Investment	Total investment at start-up was approximately NOK 3.2 billion (2010 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	Approximately 2 billion scm gas per year	

This 16-inch gas pipeline runs for 250 kilometres from the Heidrun field in the Norwegian Sea to Tjeldbergodden. The pipeline became operational in 1996.

Heidrun Gas Export

Operator	Statoil Petroleum AS[1]	
Licensees	Petoro AS	58.16 %
	ConocoPhillips Skandinavia AS	24.31 %
	Statoil Petroleum AS	12.41 %
	Eni Norge AS	5.12 %
Investment	Total investment at start-up was approximately NOK 1.0 billion (2010 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 4.0 billion scm per year	

[1] The plan is to transfer the operatorship to Gassco AS.

This 16-inch pipeline runs 37 kilometres from the Heidrun field to the Åsgard Transport system. It became operational in 2001.

Kvitebjørn Oil Pipeline (KOR)

Operator	Statoil Petroleum AS	
Licensees	Statoil Petroleum AS	58.55 %
	Petoro AS	30.00 %
	Total E&P Norge AS	5.00 %
	Enterprise Oil Norge AS	6.45 %
Investment	Total investment at start-up was approximately NOK 0.5 billion (2010 value)	
Operating lifetime	The technical operating lifetime is 25 years	
Capacity	Approximately 10 000 scm per day	

Kvitebjørn Oil Pipeline (KOR) transports condensate from Kvitebjørn to the Mongstad oil terminal. This 16-inch line runs for about 90 kilometres to tie in to the Y-connection on Troll Oil Pipeline II. The pipeline became operational in 2004.

Norpipe Oil Pipeline

Owner	Norpipe Oil AS	
Operator	ConocoPhillips Skandinavia AS	
Ownership in Norpipe Oil AS	ConocoPhillips Skandinavia AS	35.05 %
	Total E&P Norge AS	34.93 %
	Statoil Petroleum AS	18.50 %
	Eni Norge AS	6.52 %
	Petoro AS	5.00 %
Investment	Total investment at start-up was approximately NOK 17.8 billion (2010 value)	
Operating lifetime	The pipeline has been designed for an operating life of at least 30 years. The technical lifetime is under constant review.	
Capacity	Design capacity for the oil pipeline is about 53 million scm per year (900 000 bbls/day), including the use of friction-inhibiting chemicals. The receiving facilities restrict capacity to 128 776 scm per day.	

The Norpipe Oil Pipeline crosses the British continental shelf, with landfall at Teesside in the UK. The pipeline became operational in 1975. The 34-inch Norpipe oil pipeline is about 354 kilometres long and starts at the Ekofisk Centre, where three pumps have been placed. A tie-in point for UK fields is located about 50 kilometres downstream of Ekofisk. Two riser facilities, each with three pumps, were previously tied to the pipeline, but were bypassed in 1991 and 1994 respectively.

Two British-registered companies, Norsea Pipeline Ltd and Norpipe Petroleum UK Ltd, own the oil export port and fractionation plant for extracting NGL in Teesside. The pipeline carries crude from the four Ekofisk fields (Ekofisk, Eldfisk, Embla and Tor) as well as from Valhall, Hod, Ula, Gyda and Tambar, and from several British fields.

(Agreement between Norway and the UK concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to the UK, ref. Storting Proposition No. 110 (1972–1973) and Recommendation No. 262 (1972–1973).)

Oseberg Transport System (OTS)

Operator	Statoil Petroleum AS	
Licensees	Petoro AS	48.38 %
	Statoil Petroleum AS	36.24 %
	Total E&P Norge AS	8.65 %
	ExxonMobil Exploration & Production Norway AS	4.33 %
	ConocoPhillips Skandinavia AS	2.40 %
Investment	Total investment at start-up was approximately NOK 10.5 billion. (2010 value)	
Operating lifetime	The pipeline is designed for a lifetime of 40 years	
Capacity	121 000 scm per day (technical), 990 000 scm (storage)	

Oil from the Oseberg field is transported in a 115 kilometres long, 28-inch line from the Oseberg A facility to the crude oil terminal at Stura in Øygarden municipality. The pipeline became operational in 1988. The Oseberg licensees have established a separate partnership to operate this pipeline.

Sleipner Øst Condensate pipeline

Operator	Statoil Petroleum AS	
Licensees	Statoil Petroleum AS	59.60 %
	ExxonMobil Exploration and Production Norway AS	30.40 %
	Total E&P Norge AS	10.00 %
Investment	Total investment at start-up was approximately NOK 1.7 billion. (2010 value)	
Capacity	32 000 scm oil per day	

This 20-inch pipeline transports unstabilised condensate from Sleipner A to Kårstø and came in operation in 1993.

Troll Oil Pipeline I

Operator	Statoil Petroleum AS	
Licensees	Petoro AS	55.77 %
	Statoil Petroleum AS	30.58 %
	A/S Norske Shell	8.29 %
	Total E&P Norge AS	3.71 %
	ConocoPhillips Skandinavia AS	1.66 %
Investment	Total investment at start-up was approximately NOK 1.3 billion. (2010 value)	
Operating lifetime	The pipeline is designed to operate for 35 years	
Capacity	42 500 scm per day of oil with use of friction inhibitors	

Troll Oil Pipeline I was built to transport oil from Troll B to the oil terminal at Mongstad. The pipeline has a diameter of 16 inches and a length of 85 kilometres. The Troll licensees have established a separate partnership to handle operation of the line. Troll Oil Pipeline I was in place and ready to receive oil production from Troll B, which started in 1995.

Troll Oil Pipeline II

Operator	Statoil Petroleum AS	
Licensees	Petoro AS	55.77 %
	Statoil Petroleum AS	30.58 %
	A/S Norske Shell	8.29 %
	Total E&P Norge AS	3.71 %
	ConocoPhillips Skandinavia AS	1.66 %
Investment	Total investment at start-up was approximately NOK 1.2 billion. (2010 value)	
Operating lifetime	The pipeline is designed for a lifetime of 35 years	
Capacity	Current capacity is 40 000 scm per day. The hydraulic capacity is 47 500 scm per day (without use of friction inhibitors)	

This 20-inch pipeline has been built to transport oil over the 80 kilometres from Troll C to the terminal at Mongstad. The plan for installation and operation was approved in March 1998, and Troll Oil Pipeline II was ready to begin operation when Troll C started production in 1999. Oil from Fram and Kvitebjørn is transported through Troll Oil Pipeline II. The licence period for the pipeline lasts to 2023. The oil pipeline from Gjøa will be connected to Troll Oil Pipeline II, and oil from Gjøa, Vega and Vega Sør will use available capacity in the pipeline.

Onshore facilities

Mongstad crude oil terminal

Owners	Statoil Petroleum AS	65.00 %
	Petoro AS	35.00 %

The terminal at Mongstad incorporates three jetties able to receive vessels up to 440 000 tonnes, as well as six caverns blasted in the bedrock 50 metres below ground. These caverns have a total storage capacity of 1.5 million m^3 of crude oil.

This facility was constructed to support the marketing of crude oil loaded offshore. Crude oil from fields with buoy loading (including Gullfaks, Statfjord, Draugen, Norne, Åsgard and Heidrun) is loaded offshore onto shuttle tankers, which have a sailing range confined to northwest Europe. However, by storing and transhipping crude at Mongstad, Statoil can sell the oil to more distant destinations. Mongstad is also the receiving terminal for the oil pipelines from Troll B, Troll C, Fram and Kvitebjørn fields, as well as shuttle tankers from Heidrun.

Nyhamna onshore facility

Owner	As for the Ormen Lange field

The process plant for Ormen Lange at Nyhamna is a conventional plant for gas drying, compression, gas export, condensate separation/stabilisation/storage and fiscal measurement of gas and condensate. The condensate is being exported by ship from Nyhamna. The plant became operational in 2007. The land facility has been designed for an operating life of 30 years, while part of the main infrastructure has been designed for 50 years. The plant has a capacity of 70 million scm dry gas per day at a receiving pressure of 90 bar.

Melkøya onshore facility

Owner	As for the Snøhvit field

The unprocessed well stream from the Snøhvit field is transported through a 143 kilometres long pipeline to the facility at Melkøya for processing and export. Condensate, water and CO_2 are separated from the well stream on the onshore facility before the natural gas is being cooled down to liquid form (LNG) and stored in dedicated tanks. The pipeline became operational in 2007 and has an available technical capacity of 7.7 million scm per year. Power is normally supplied by five gas turbines at the facility. Condensate and LPG products are stored in tanks for export. Separated CO_2 is sent in return to the Snøhvit field and injected into a separate formation below the oil and gas.

Sture Terminal

Owner	The Sture terminal forms part of the joint venture for the Oseberg Transport System (OTS), with the same ownership interests. The exception is the LPG export facilities, which are owned by Statoil Petroleum AS (the refrigerated LPG storage and transfer system to ships) and Vestprosess DA (export facility to Vestprosess).

The Sture oil terminal receives oil and condensate via the pipeline from the Oseberg A facility from the Oseberg, Veslefrikk, Brage, Oseberg Sør, Oseberg Øst, Tune and Huldra fields. The terminal also receives Grane oil through the Grane Oil Pipeline. The terminal began operating in 1988. It incorporates two jet-ties able to berth oil tankers up to 300 000 tonnes, five rock caverns for storing crude oil with a combined capacity of 1 million scm, a 60 000 m^3 rock cavern storage for LPG and a 200 000 m^3 ballast water cavern. A separate unit for recovering volatile organic compounds (VOC) has been installed.

A fractionation plant which came in operation in December 1999 processes unstabilised crude from Oseberg into stabilised oil and an LPG blend. The produced LPG blend can either be exported by ship from the terminal or sent through the Vestprosess pipeline between Kollsnes, Stura and Mongstad.

Tjeldbergodden

Owner	Statoil Metanol ANS	
Owners in Statoil Metanol ANS	Statoil Petroleum AS	81.70 %
	ConocoPhillips Skandinavia AS	18.30 %

The methanol plant at Tjeldbergodden began production in 1997. Gas deliveries through the Haltenpipe total 0.7 billion scm annually, which yield 830 000 tonnes of methanol.

An air separation plant, Tjeldbergodden Luftgassfabrikk DA, has been built in connection with the methanol facility. Tjeldbergodden Luftgassfabrikk DA has also a small gas fractionation and liquefaction plant with an annual capacity of 35 million scm.

Vestprosess

Owners	Petoro AS	41.00 %
	Statoil Petroleum AS	34.00 %
	Mobil Exploration Norway Inc	10.00 %
	A/S Norske Shell	8.00 %
	Total E&P Norge AS	5.00 %
	ConocoPhillips Skandinavia AS	2.00 %

The Vestprosess DA partnership owns and operates a gas transport system and a gas separation facility for NGL. These facilities came on stream in 1999. A 56 kilometres pipeline carries unstabilised NGL from the Kollsnes gas terminal, via the oil terminal at Stura, to Mongstad.

At Mongstad, processing starts by separating out naphtha and LPG. The naphtha serves as refinery feed-stock, while the LPG is fractionated in a dedicated process into propane and butane. These products are stored in rock caverns before export.

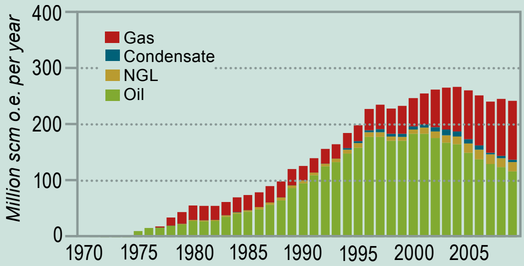
APPENDIX

Appendix 1 Historical statistics

Table 1.1 The state's revenues from petroleum activities (MNOK)

Year	Ordinary tax	Special tax	Production fee	Area fee	Environ-mental taxes	Net cash flow SDFI	Dividend Statoil
1971			14				
1972			42				
1973			69				
1974			121				
1975			208				
1976	1 143	4	712	99			
1977	1 694	725	646	57			
1978	1 828	727	1 213	51			
1979	3 399	1 492	1 608	53			
1980	9 912	4 955	3 639	63			
1981	13 804	8 062	5 308	69			0.057
1982	15 036	9 014	5 757	76			368
1983	14 232	8 870	7 663	75			353
1984	18 333	11 078	9 718	84			795
1985	21 809	13 013	11 626	219		-8 343	709
1986	17 308	9 996	8 172	198		-11 960	1 245
1987	7 137	3 184	7 517	243		-10 711	871
1988	5 129	1 072	5 481	184		-9 133	0
1989	4 832	1 547	7 288	223		755	0
1990	12 366	4 963	8 471	258		7 344	800
1991	15 021	6 739	8 940	582	810	5 879	1 500
1992	7 558	7 265	8 129	614	1 916	3 623	1 400
1993	6 411	9 528	7 852	553	2 271	159	1 250
1994	6 238	8 967	6 595	139	2 557	5	1 075
1995	7 854	10 789	5 884	552	2 559	9 259	1 614
1996	9 940	12 890	6 301	1 159	2 787	34 959	1 850
1997	15 489	19 582	6 220	617	3 043	40 404	1 600
1998	9 089	11 001	3 755	527	3 229	14 572	2 940
1999	5 540	6 151	3 222	561	3 261	25 769	135
2000	21 921	32 901	3 463	122	3 047	98 219	1 702
2001	41 465	64 316	2 481	983	2 862	125 439	5 746
2002	32 512	52 410	1 320	447	3 012	74 785	5 045
2003	36 819	60 280	766	460	3 056	67 482	5 133
2004	43 177	70 443	717	496	3 309	80 166	5 222
2005	61 589	103 294	360	224	3 351	98 602	8 139
2006	78 015	133 492	42	2 308	3 405	125 523	12 593
2007	70 281	116 233	0	764	3 876	111 235	14 006
2008	88 802	150 839	0	1 842	3 684	153 771	16 940
2009	61 501	103 733	0	1 470	2 262	95 339	15 489

(Source: Norwegian Public Accounts, National Budget and account figures for SDFI)



Total petroleum production

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

Table 1.2 Petroleum production on the Norwegian continental shelf, millions standard cubic meter oil equivelents

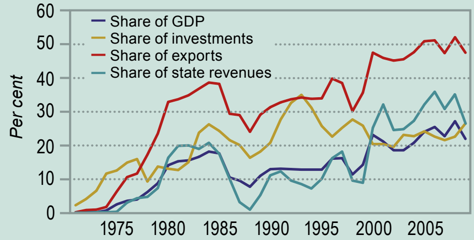
Year	Oil	Gas	Condensate	NGL	Total production
1970					
1971	0.4	0.0	0.0	0.0	0.4
1972	1.9	0.0	0.0	0.0	1.9
1973	1.9	0.0	0.0	0.0	1.9
1974	2.0	0.0	0.0	0.0	2.0
1975	11.0	0.0	0.0	0.0	11.0
1976	16.2	0.0	0.0	0.0	16.2
1977	16.6	2.65	0.0	0.0	19.3
1978	20.6	14.20	0.0	0.0	34.9
1979	22.5	20.67	0.0	1.1	44.3
1980	28.2	25.09	0.0	2.4	55.8
1981	27.5	24.95	0.0	2.2	54.7
1982	28.5	23.96	0.0	2.3	54.8
1983	35.6	23.61	0.0	2.7	62.0
1984	41.1	25.96	0.1	2.6	69.8
1985	44.8	26.19	0.1	3.0	74.0
1986	48.8	26.09	0.1	3.8	78.8
1987	57.0	28.15	0.1	4.1	89.3
1988	64.7	28.33	0.0	4.8	97.9
1989	86.0	28.74	0.1	4.9	119.7
1990	94.5	25.48	0.0	5.0	125.1
1991	108.5	25.03	0.1	4.9	138.5
1992	124.0	25.83	0.1	5.0	154.8
1993	131.8	24.80	0.5	5.5	162.6
1994	146.3	26.84	2.4	7.1	182.6
1995	156.8	27.81	3.2	7.9	195.7
1996	175.4	37.41	3.8	8.2	224.9
1997	175.9	42.85	5.4	8.1	232.3
1998	168.7	44.19	5.0	7.4	225.4
1999	168.7	48.48	5.5	7.0	229.7
2000	181.2	49.75	5.4	7.2	243.6
2001	180.9	53.89	5.7	10.9	251.4
2002	173.6	65.50	7.3	11.8	258.3
2003	165.5	73.12	10.3	12.9	261.8
2004	162.8	78.33	8.7	13.6	263.4
2005	148.1	84.96	8.0	15.7	256.8
2006	136.6	87.61	7.6	16.7	248.5
2007	128.3	89.66	3.1	16.6	237.6
2008	122.7	99.25	3.9	16.0	241.8
2009	115.5	102.71	4.4	16.0	238.6

(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

Table 1.3 Value creation, exports, employment, investments and exploration costs

Year	Gross product (MNOK)	Export value (MNOK)	Numbers of employees	Investment incl. exploration costs (MNOK)	Exploration costs (MNOK)
1971	12	75	NA	704	
1972	207	314	200	1 274	
1973	258	504	300	2 457	
1974	1 056	1 089	1 000	5 313	
1975	4 218	3 943	2 400	7 227	
1976	6 896	7 438	3 000	10 421	
1977	8 617	8 852	4 400	12 621	
1978	14 835	15 117	6 900	6 912	
1979	23 494	24 788	8 800	10 792	
1980	44 285	44 638	10 900	11 000	
1981	55 189	52 432	13 700	12 262	4 133
1982	61 891	57 623	14 600	16 148	5 519
1983	73 298	68 082	15 500	28 883	5 884
1984	90 092	82 504	17 700	34 029	7 491
1985	97 347	90 098	19 900	32 730	7 830
1986	59 988	57 239	20 200	33 302	6 654
1987	59 574	58 301	20 100	34 247	4 951
1988	49 966	51 720	21 000	29 522	4 151
1989	76 768	76 681	21 100	31 777	5 008
1990	95 400	92 451	21 600	31 976	5 137
1991	101 346	101 015	22 100	42 634	8 137
1992	102 578	101 187	23 500	49 196	7 680
1993	107 542	108 463	25 200	57 168	5 433
1994	112 623	113 099	25 400	54 189	5 011
1995	120 198	121 169	24 400	47 890	4 647
1996	165 444	167 200	24 800	47 158	5 456
1997	180 594	177 825	27 100	61 774	8 300
1998	129 098	128 807	27 800	78 683	7 577
1999	176 591	173 428	27 600	70 041	4 992
2000	340 640	326 658	26 500	55 406	5 272
2001	325 333	322 291	30 000	56 548	6 815
2002	283 462	283 343	33 000	53 398	4 476
2003	295 356	291 220	32 700	63 597	4 134
2004	361 262	347 926	32 600	71 285	4 010
2005	465 341	439 881	34 600	88 256	7 537
2006	548 837	511 354	36 400	95 477	11 718
2007	516 218	490 930	38 900	108 252	17 921
2008	689 795	633 573	41 200	122 237	24 411
2009	526 829	476 410	43 100	136 463	27 889

(Source: Statistics Norway)



Macroeconomic indicators for the petroleum sector

(Source: Statistics Norway, Ministry of Finance)

Table 1.4 The petroleum sector's percentage share of the gross national product, exports, real investments and the state's total revenues

Year	Share of gross national product	Share of exports	Share of real investments	Share of state's total revenues
1971	0.01	0.21	2.33	0.05
1972	0.18	0.79	4.03	0.12
1973	0.20	1.04	6.56	0.16
1974	0.71	1.82	11.61	0.25
1975	2.48	6.36	12.56	0.38
1976	3.55	10.54	14.86	3.07
1977	3.94	11.68	15.92	4.38
1978	6.15	17.23	9.27	4.77
1979	8.83	23.47	13.68	7.31
1980	14.07	32.80	13.03	16.27
1981	15.30	33.58	12.69	19.76
1982	15.50	34.80	15.00	19.90
1983	16.53	36.69	23.71	18.86
1984	18.07	38.55	26.18	20.74
1985	17.62	38.16	24.26	17.50
1986	10.51	29.29	21.43	10.13
1987	9.56	28.91	20.04	3.21
1988	7.66	23.99	16.27	1.02
1989	11.03	28.99	18.15	5.20
1990	12.96	31.28	20.76	11.14
1991	13.06	32.60	27.65	12.25
1992	12.87	33.51	32.53	9.49
1993	12.83	34.12	34.84	8.50
1994	12.82	33.76	31.08	7.24
1995	12.74	33.83	25.64	10.06
1996	16.02	39.69	22.60	16.14
1997	16.14	38.42	25.13	18.15
1998	11.32	30.00	27.62	9.56
1999	14.24	35.49	25.74	8.93
2000	23.00	47.39	20.31	25.07
2001	21.17	45.82	20.28	32.07
2002	18.50	44.96	19.49	24.50
2003	18.53	45.35	23.03	24.80
2004	20.73	47.49	22.68	27.25
2005	23.92	50.66	24.14	32.01
2006	25.41	51.01	22.51	35.72
2007	22.72	47.22	21.48	30.71
2008	27.12	51.82	22.55	35.17
2009	21.88	47.38	26.48	26.59

(Source: Statistics Norway, Ministry of Finance)

Appendix 2 The petroleum resources

(per 31.12.2009)

Table 2.1 Historical production from fields in production and fields with ceased production

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill scm o.e.	Year of discovery[2]
Albuskjell	7.4	15.5	1.0		24.8	1972
Cod	2.9	7.3	0.5		11.2	1968
Edda	4.8	2.0	0.2		7.2	1972
Frigg		116.2		0.5	116.6	1971
Frøy	5.6	1.6		0.1	7.3	1987
Lille-Frigg	1.3	2.2		0.0	3.5	1975
Mime	0.4	0.1	0.0		0.5	1982
Nordøst Frigg		11.6		0.1	11.7	1974
Odin		27.3		0.2	27.5	1974
Tommeliten Gamma	3.9	9.7	0.6		14.6	1978
Vest Ekofisk	12.2	26.0	1.4		40.8	1970
Øst Frigg		9.2		0.1	9.3	1973
Historical production	**38.3**	**228.6**	**3.7**	**0.9**	**274.9**	
33/9-6 Delta[3]	0.0		0.0		0.0	1976
Alve	0.3	0.9	0.2		1.5	1990
Alvheim	7.3	0.6			7.9	1998
Balder[a]	49.0	1.1			50.2	1967
Blane	0.3		0.0		0.3	1989
Brage	51.8	2.9	1.1		56.7	1980
Draugen	125.3	1.4	2.2		130.8	1984
Ekofisk	414.0	137.7	12.5		575.5	1969
Eldfisk	92.1	38.1	3.7		137.4	1970
Embla	9.9	3.5	0.4		14.1	1988
Enoch	0.2	0.0			0.2	1991
Fram	16.5	0.8	0.1		17.4	1992
Gimle	2.0	0.1	0.0		2.1	2004
Glitne	8.3	0.0		0.0	8.3	1995
Grane	63.6				63.6	1991
Gullfaks[b]	344.7	23.0	2.8		373.1	1978
Gullfaks Sør[c]	36.6	26.6	3.3		69.5	1978
Gungne		12.8	1.7	4.1	20.1	1982
Gyda[d]	35.1	6.0	1.9		44.7	1980
Heidrun[e]	131.9	12.7	0.5		145.6	1985
Heimdal	6.5	44.4			50.9	1972
Hod	9.2	1.6	0.3		11.3	1974
Huldra	4.8	14.9	0.1		19.8	1982
Jotun	22.1	0.9			22.9	1994
Kristin	12.6	13.3	2.8	2.1	33.4	1997
Kvitebjørn	9.7	19.7	1.8		32.7	1994
Mikkel	2.0	10.6	2.8	2.2	20.2	1987
Murchison	13.7	0.3	0.3	0.0	14.6	1975
Njord	23.7	3.9			27.6	1986
Norne	82.7	6.0	0.7		90.0	1992

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill scm o.e.	Year of discovery[2]
Ormen Lange		33.9		2.7	36.6	1997
Oseberg[f]	350.4	24.2	6.3		386.6	1979
Oseberg Sør	37.3	5.9			43.2	1984
Oseberg Øst	17.4	0.3			17.7	1981
Rev	0.2	0.6			0.9	2001
Ringhorne Øst	6.1	0.1			6.3	2003
Sigyn		5.0	2.0	4.9	13.6	1982
Skirne	1.4	6.5			7.9	1990
Sleipner Vest and Øst[4) g)]		157.7	19.3	50.9	245.3	1974
Snorre	170.0	6.0	4.5		184.6	1979
Snøhvit		5.8	0.3	1.2	7.6	1984
Statfjord	560.7	61.0	15.9	0.4	652.4	1974
Statfjord Nord	35.7	2.2	0.8		39.4	1977
Statfjord Øst	34.4	3.7	1.3		40.5	1976
Sygna	9.7				9.7	1996
Tambar	8.2	1.9	0.2		10.5	1983
Tambar Øst	0.2				0.2	2007
Tor	23.2	10.8	1.2		36.2	1970
Tordis[h]	53.7	3.8	1.4		60.2	1987
Troll[i]	206.5	360.1	4.2	4.3	578.9	1979
Tune	3.0	16.2	0.1		19.5	1996
Tyrihans	1.6	0.3	0.1		2.0	1983
Ula	69.9	3.9	2.6		78.6	1976
Urd	4.0	0.1	0.0		4.1	2000
Vale	1.2	0.9			2.1	1991
Valhall	101.2	19.8	3.2		127.1	1975
Varg	12.0				12.0	1984
Veslefrikk	50.1	2.2	1.2		54.6	1981
Vigdis	45.7	1.3	0.8		48.4	1986
Vilje	2.1	0.1			2.2	2003
Visund	19.6	4.8	0.3		25.1	1986
Volund	0.0	0.0			0.0	1994
Volve	4.5	0.5	0.1	0.1	5.2	1993
Yme	7.9				7.9	1987
Yttergryta	0.1	0.3	0.1		0.5	2007
Åsgard	68.8	87.3	15.3	17.1	202.4	1981
Producing fields	**3482.6**	**1211.1**	**120.4**	**90.0**	**5012.5**	
Total sold and delivered	**3520.9**	**1439.7**	**124.1**	**91.0**	**5287.5**	

1) The conversion factor for NGL tonnes to scm is 1.9.
2) The year the first discovery well was drilled
3) 33/9-6 Delta has test production
4) Gas production from Sleipner Vest and Sleipner Øst are metered collectively.

(Source: Norwegian Petroleum Directorate)

a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør also include Gulltopp, Gullveig, Rimfaks and Skinnfaks
d) Gyda also includes Gyda Sør
e) Heidrun also includes Tjeldbergodden
f) Oseberg also includes Oseberg Vest
g) Sleipner Øst also includes Loke
h) Tordis also include Tordis Øst and Borg
i) Troll also includes TOGI

Table 2.2 Reserves in fields in production and fields with approved plans for development and operation

Field	Reserves mill. scm o.e.	Year of discovery[4)]	Operator at 31.12.2009	Production licence/ unit area
Alve	8.3	1990	Statoil Petroleum AS	159 B
Alvheim	42.4	1998	Marathon Petroleum Norge AS	036 C, 088 BS, 203
Balder	63.6	1967	ExxonMobil Exploration & Production Norway AS	001
Blane	0.9	1989	Talisman Energy Norge AS	Blane
Brage	62.7	1980	Statoil Petroleum AS	Brage
Draugen	151.8	1984	A/S Norske Shell	093
Ekofisk	716.8	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	183.7	1970	ConocoPhillips Skandinavia AS	018
Embla	15.4	1988	ConocoPhillips Skandinavia AS	018
Enoch	0.5	1991	Talisman North Sea Limited	Enoch
Fram	35.1	1992	Statoil Petroleum AS	090
Gimle	4.7	2004	Statoil Petroleum AS	Gimle
Gjøa[1)]	55.6	1989	Statoil Petroleum AS	153
Glitne	8.6	1995	Statoil Petroleum AS	048 B
Goliat[1)]	38.5	2000	Eni Norge AS	229
Grane	116.7	1991	Statoil Petroleum AS	Grane
Gullfaks	389.8	1978	Statoil Petroleum AS	050
Gullfaks Sør	127.0	1978	Statoil Petroleum AS	050
Gungne	23.4	1982	Statoil Petroleum AS	046
Gyda	50.5	1980	Talisman Energy Norge AS	019 B
Heidrun	216.8	1985	Statoil Petroleum AS	Heidrun
Heimdal	52.0	1972	Statoil Petroleum AS	036 BS
Hod	12.2	1974	BP Norge As	033
Huldra	21.1	1982	Statoil Petroleum AS	Huldra
Jotun	24.3	1994	ExxonMobil Exploration & Production Norway AS	Jotun
Kristin	62.9	1997	Statoil Petroleum AS	Haltenbanken Vest
Kvitebjørn	107.9	1994	Statoil Petroleum AS	193
Mikkel	41.6	1987	Statoil Petroleum AS	Mikkel
Morvin[1)]	13.7	2001	Statoil Petroleum AS	134 B
Murchison	14.7	1975	CNR International (UK) Limited	Murchison
Njord	40.5	1986	Statoil Petroleum AS	Njord
Norne	108.3	1992	Statoil Petroleum AS	Norne
Ormen Lange	320.3	1997	A/S Norske Shell	Ormen Lange
Oseberg[2)]	500.5	1979	Statoil Petroleum AS	Oseberg
Oseberg Sør	67.5	1984	Statoil Petroleum AS	Oseberg
Oseberg Øst	29.1	1981	Statoil Petroleum AS	Oseberg
Oselvar[1)]	8.6	1991	Dong E & P Norge AS	274
Rev	4.6	2001	Talisman Energy Norge AS	038 C

Field	Reserves mill. scm o.e.	Year of discovery[4]	Operator at 31.12.2009	Production licence/ unit area
Ringhorne Øst	12.2	2003	ExxonMobil Exploration & Production Norway AS	Ringhorne Øst
Sigyn	16.8	1982	ExxonMobil Exploration & Production Norway AS	072
Skarv[1]	69.0	1998	BP Norge AS	Skarv
Skirne	10.8	1990	Total E&P Norge AS	102
Sleipner Vest	166.9	1974	Statoil Petroleum AS	Sleipner Vest
Sleipner Øst	117.9	1981	Statoil Petroleum AS	Sleipner Øst
Snorre	253.7	1979	Statoil Petroleum AS	Snorre
Snøhvit	190.9	1984	Statoil Petroleum AS	Snøhvit
Statfjord	684.4	1974	Statoil Petroleum AS	Statfjord
Statfjord Nord	43.3	1977	Statoil Petroleum AS	037
Statfjord Øst	43.4	1976	Statoil Petroleum AS	Statfjord Øst
Sygna	10.7	1996	Statoil Petroleum AS	Sygna
Tambar	11.4	1983	BP Norge AS	065
Tambar Øst	0.3	2007	BP Norge AS	Tambar Øst
Tor	36.6	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	68.9	1987	Statoil Petroleum AS	089
Troll[3]	1629.6	1979	Statoil Petroleum AS	Troll
Tune	21.6	1996	Statoil Petroleum AS	190
Tyrihans	77.6	1983	Statoil Petroleum AS	Tyrihans
Ula	102.2	1976	BP Norge AS	019
Urd	8.8	2000	Statoil Petroleum AS	128
Vale	4.2	1991	Statoil Petroleum AS	036
Valhall	180.9	1975	BP Norge AS	Valhall
Varg	16.5	1984	Talisman Energy Norge AS	038
Vega[1]	12.1	1981	Statoil Petroleum AS	248
Vega Sør[1]	13.1	1987	Statoil Petroleum AS	090 C
Veslefrikk	62.3	1981	Statoil Petroleum AS	052
Vigdis	61.8	1986	Statoil Petroleum AS	089
Vilje	8.3	2003	Statoil Petroleum AS	036 D
Visund	89.8	1986	Statoil Petroleum AS	Visund
Volund	8.0	1994	Marathon Petroleum Norge AS	150
Volve	9.9	1993	Statoil Petroleum AS	046 BS
Yme[1]	19.3	1987	Talisman Energy Norge AS	316
Yttergryta	2.6	2007	Statoil Petroleum AS	62
Åsgard	368.6	1981	Statoil Petroleum AS	Åsgard

1) Fields with approved development plans where production had not started at 31.12.2009
2) Resources in Oseberg also include Oseberg Vest
3) The resources include the total resources for Troll
4) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.3 Original recoverable reserves and remaining reserves in fields

	Original reserves[1)]					Remaining reserves[4)]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2)] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2)] mill.scm o.e.
Alve	1.0	5.3	1.0	0.0	8.3	0.7	4.4	0.9	0.0	6.8
Alvheim	34.4	7.9	0.0	0.0	42.4	27.2	7.3	0.0	0.0	34.5
Balder[a)]	61.8	1.8	0.0	0.0	63.6	12.7	0.7	0.0	0.0	13.4
Blane	0.9	0.0	0.0	0.0	0.9	0.6	0.0	0.0	0.0	0.6
Brage	56.6	3.7	1.2	0.0	62.7	4.8	0.8	0.2	0.0	5.9
Draugen	145.0	1.6	2.7	0.0	151.8	19.7	0.1	0.6	0.0	20.9
Ekofisk	532.6	156.5	14.6	0.0	716.8	118.5	18.8	2.0	0.0	141.3
Eldfisk	132.2	44.0	4.0	0.0	183.7	40.0	5.9	0.2	0.0	46.3
Embla	10.4	4.1	0.5	0.0	15.4	0.5	0.7	0.1	0.0	1.3
Enoch	0.5	0.0	0.0	0.0	0.5	0.3	0.0	0.0	0.0	0.3
Fram	25.7	8.5	0.5	0.0	35.1	9.3	7.7	0.4	0.0	17.8
Gimle	3.4	0.9	0.2	0.0	4.7	1.4	0.8	0.2	0.0	2.5
Gjøa[3)]	10.3	34.2	5.9	0.0	55.6	10.3	34.2	5.9	0.0	55.6
Glitne	8.6	0.0	0.0	0.0	8.6	0.2	0.0	0.0	0.0	0.2
Goliat[3)]	30.6	7.3	0.3	0.0	38.5	30.6	7.3	0.3	0.0	38.5
Grane	116.7	0.0	0.0	0.0	116.7	53.1	0.0	0.0	0.0	53.1
Gullfaks[b)]	361.5	22.7	2.9	0.0	389.8	16.8	0.0	0.1	0.0	17.0
Gullfaks Sør[c)]	51.3	61.5	7.5	0.0	127.0	14.6	34.9	4.2	0.0	57.6
Gungne	0.0	15.0	2.0	4.6	23.4	0.0	2.2	0.3	0.5	3.3
Gyda[d)]	39.6	7.0	2.0	0.0	50.5	4.5	1.0	0.2	0.0	5.9
Heidrun[e)]	170.0	42.6	2.2	0.0	216.8	38.1	29.9	1.7	0.0	71.2
Heimdal	7.2	44.8	0.0	0.0	52.0	0.7	0.4	0.0	0.0	1.1
Hod	9.8	1.7	0.4	0.0	12.2	0.6	0.1	0.1	0.0	0.9
Huldra	4.9	16.0	0.1	0.0	21.1	0.1	1.1	0.0	0.0	1.2
Jotun	23.4	0.9	0.0	0.0	24.3	1.3	0.1	0.0	0.0	1.4
Kristin	23.9	25.9	5.8	2.1	62.9	11.3	12.6	3.0	0.0	29.5
Kvitebjørn	25.3	75.0	4.1	0.0	107.9	15.6	55.3	2.3	0.0	75.2
Mikkel	4.6	22.8	6.3	2.3	41.6	2.6	12.2	3.4	0.0	21.3
Morvin[3)]	9.3	3.2	0.7	0.0	13.7	9.3	3.2	0.7	0.0	13.7
Murchison	14.3	0.4	0.0	0.0	14.7	0.6	0.1	0.0	0.0	0.6
Njord	26.1	10.4	2.1	0.0	40.5	2.4	6.5	2.1	0.0	12.8
Norne	94.7	10.5	1.6	0.0	108.3	12.0	4.5	0.9	0.0	18.3
Ormen Lange	0.0	301.7	0.0	18.6	320.3	0.0	267.8	0.0	15.8	283.6
Oseberg[f)]	374.8	105.7	10.5	0.0	500.5	24.4	81.5	4.2	0.0	113.9
Oseberg Sør	52.7	11.8	1.5	0.0	67.5	15.5	5.9	1.5	0.0	24.3
Oseberg Øst	28.6	0.4	0.1	0.0	29.1	11.1	0.1	0.1	0.0	11.4
Oselvar[3)]	4.0	4.6	0.0	0.0	8.6	4.0	4.6	0.0	0.0	8.6
Rev	0.7	3.4	0.2	0.0	4.6	0.5	2.8	0.2	0.0	3.8
Ringhorne Øst	11.8	0.4	0.0	0.0	12.2	5.7	0.2	0.0	0.0	5.9
Sigyn	0.0	6.7	2.8	4.9	16.8	0.0	1.7	0.8	0.0	3.2
Skarv[3)]	16.5	42.1	5.5	0.0	69.0	16.5	42.1	5.5	0.0	69.0

	Original reserves[1]					Remaining reserves[4]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[2] mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv.[2] mill.scm o.e.
Skirne	2.1	8.7	0.0	0.0	10.8	0.7	2.3	0.0	0.0	2.9
Sleipner Vest	0.0	121.3	8.5	29.6	166.9					
Sleipner Øst[g]	0.0	67.4	12.8	26.3	117.9					
Sleipner Vest and Sleipner Øst[5]						0.0	30.9	1.9	5.0	39.5
Snorre	238.3	6.5	4.7	0.0	253.7	68.3	0.5	0.2	0.0	69.1
Snøhvit	0.0	160.6	6.4	18.1	190.9	0.0	154.8	6.1	16.9	183.2
Statfjord	565.8	74.3	23.3	0.0	684.4	5.1	13.3	7.3	0.0	32.3
Statfjord Nord	39.3	2.1	1.1	0.0	43.3	3.6	0.0	0.3	0.0	4.1
Statfjord Øst	35.7	3.8	2.0	0.0	43.4	1.3	0.1	0.7	0.0	2.8
Sygna	10.7	0.0	0.0	0.0	10.7	1.0	0.0	0.0	0.0	1.0
Tambar	8.9	2.0	0.3	0.0	11.4	0.7	0.2	0.0	0.0	1.0
Tambar Øst	0.3	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.1
Tor	23.5	10.9	1.2	0.0	36.6	0.3	0.1	0.0	0.0	0.3
Tordis[h]	60.3	5.3	1.7	0.0	68.9	6.5	1.5	0.3	0.0	8.7
Troll[i]	248.5	1330.7	25.7	1.6	1629.6	42.0	970.6	21.5	-2.7	1050.6
Tune	3.2	18.0	0.2	0.0	21.6	0.2	1.8	0.1	0.0	2.1
Tyrihans	29.6	35.5	6.5	0.0	77.6	28.0	35.3	6.5	0.0	75.6
Ula	91.8	3.9	3.4	0.0	102.2	21.9	0.0	0.9	0.0	23.6
Urd	8.7	0.1	0.0	0.0	8.8	4.7	0.0	0.0	0.0	4.7
Vale	2.0	2.2	0.0	0.0	4.2	0.8	1.2	0.0	0.0	2.0
Valhall	144.2	26.6	5.4	0.0	180.9	43.0	6.7	2.2	0.0	53.8
Varg	16.5	0.0	0.0	0.0	16.5	4.5	0.0	0.0	0.0	4.5
Vega[3]	1.7	9.4	0.5	0.0	12.1	1.7	9.4	0.5	0.0	12.1
Vega Sør[3]	3.6	8.7	0.4	0.0	13.1	3.6	8.7	0.4	0.0	13.1
Veslefrikk	55.0	4.3	1.6	0.0	62.3	4.9	2.2	0.3	0.0	7.7
Vigdis	58.0	1.6	1.2	0.0	61.8	12.3	0.3	0.4	0.0	13.4
Vilje	8.3	0.0	0.0	0.0	8.3	6.2	0.0	0.0	0.0	6.2
Visund	31.3	47.2	5.9	0.0	89.8	11.6	42.4	5.6	0.0	64.7
Volund	7.2	0.8	0.0	0.0	8.0	7.2	0.8	0.0	0.0	8.0
Volve	8.8	0.7	0.1	0.1	9.9	4.3	0.3	0.0	0.0	4.7
Yme[3]	19.3	0.0	0.0	0.0	19.3	11.4	0.0	0.0	0.0	11.4
Yttergryta	0.2	1.8	0.3	0.0	2.6	0.1	1.5	0.2	0.0	2.0
Åsgard	102.8	184.7	34.2	16.1	368.6	34.0	97.4	18.9	-1.1	166.2
Total	**4350.5**	**3252.3**	**236.6**	**124.1**	**8176.5**	**868.0**	**2041.9**	**116.5**	**34.5**	**3165.7**

1) The table shows expected value, the estimates are subject to uncertainty
2) The conversion factor for NGL tonnes to scm is 1.9.
3) Fields with approved development plans where production had not started at 31.12.2009
4) A negative remaining reserves figure for a field is a result of the product not being reported under original reserves. This applies to produced NGL and condensate
5) Gas production from Sleipner Vest and Øst are metered collectively

a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør includes Gulltopp,Gullveig, Rimfaks and Skinfaks
d) Gyda also includes Gyda Sør
e) Heidrun also includes Tjeldbergodden
f) Oseberg also includes Oseberg Vest
g) Sleipner Øst also include Loke
h) Tordis also includes Tordis Øst and Borg
i) Troll also includes TOGI

(Source: Norwegian Petroleum Directorate)

Table 2.4 Reserves in discoveries the licensees have decided to develop

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill. scm o.e.	Year of discovery[2]
3/7 - 4 Trym	0.0	4.2	0.0	1.1	5.4	1990
33/9-6 Delta	0.1				0.1	1976
Total	**0.1**	**4.2**	**0.0**	**1.1**	**5.4**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Table 2.5 Resources in fields and discoveries in the planning phase

Discovery	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil. equiv.[1] mill. scm o.e.	Year of discovery[2]
Frøy[3]	8.7	0.0	0.0	0.0	8.7	1987
1/5-2 Flyndre	0.2	0.0	0.0	0.0	0.2	1974
1/9-1 Tommeliten Alpha[4]	7.0	15.2	0.5	0.0	23.2	1977
7/7-2	3.1	0.0	0.0	0.0	3.1	1992
15/3-1 S Gudrun	9.3	7.8	1.1	0.0	19.2	1975
15/3-4	2.0	1.8	0.3	0.0	4.4	1982
16/1-8[5]	23.8	2.5	0.0	0.0	26.3	2007
2/12-1 Freja	3.0	0.8	0.1	0.0	4.0	1987
24/6-1 Peik	0.0	2.5	0.0	0.7	3.1	1985
25/10-8 Hanz	2.5	0.3	0.1	0.0	3.0	1997
25/11-16	12.6	0.0	0.0	0.0	12.6	1992
30/7-6 Hild	4.0	11.7	0.6	1.5	18.5	1978
31/2-N-11 H	0.4	0.0	0.0	0.0	0.4	2005
34/10-23 Valemon	7.2	39.8	1.2	0.0	49.3	1985
35/11-13	6.2	2.2	0.0	0.0	8.4	2005
35/2-1	0.0	19.5	0.0	0.00	19.5	2005
6/3-1 PI	1.0	2.2	0.2	0.09	3.7	1985
6406/3-2 Trestakk	7.7	1.8	0.5	0.00	10.4	1986
6407/9-9	0.0	1.4	0.0	0.00	1.4	1999
6507/2-2 Marulk	0.6	8.9	1.5	0.0	12.4	1992
6707/10-1[6]	0.0	53.1	0.0	0.9	54.0	1997
Total	**99.5**	**171.5**	**6.1**	**3.1**	**285.7**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled
3) The licensees look at a further development of the field
4) 1/9-1 Tommeliten Alpha has resources in categories 4 and 5
5) 16/1-8 includes resources from 16/1-12 in category 7F
6) 6707/10-1 includes resources for 6707/10-2 S and 6706/12-1

(Source: Norwegian Petroleum Directorate)

Table 2.6 Resources in discoveries where development is likely but not clarified

Discovery	Oil mill. scm	Gas bill. Scm	NGL mill. tonnes	Condensate mill. scm	Oil. equiv[1] mill. scm o.e.	Year of discovery[2]
7/8-3	2.4	0.0	0.0	0.2	2.6	1983
15/5-1 Dagny	12.0	16.7	0.0	6.4	35.2	1978
15/5-2	0.0	10.9	0.0	0.9	11.8	1978
15/8-1 Alpha	0.0	2.2	0.5	1.6	4.7	1982
16/1-9	10.6	2.9	0.5	0.0	14.4	2008
16/7-2	0.0	0.6	0.1	0.4	1.2	1982
17/12-1 Bream	8.1	0.0	0.0	0.0	8.1	1972
2/5-3 Sørøst Tor	3.1	0.9	0.0	0.0	3.9	1972
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
34/11-2 S Nøkken	1.2	2.7	0.1	0.0	4.1	1996
34/3-1 S	10.0	0.5	0.7	0.0	11.8	2008
34/8-14 S	3.2	7.4	0.9	0.0	12.3	2008
35/8-3	0.0	2.7	0.0	0.6	3.2	1988
6406/1-1 Erlend N.	0.3	0.8	0.2	0.0	1.4	2001
6406/2-1 Lavrans	2.7	8.8	1.5	0.0	14.4	1995
6406/2-6 Ragnfrid	1.7	2.1	0.5	0.0	4.7	1998
6406/2-7 Erlend	2.2	2.9	0.7	0.0	6.4	1999
6406/9-1	0.0	33.5	0.0	0.8	34.3	2005
6407/6-6[3]	0.0	2.0	0.3	0.5	3.1	2008
6407/7-8	0.0	4.6	0.9	0.4	6.7	2008
6506/11-2 Lange	0.5	0.5	0.1	0.0	1.1	1991
6506/12-3 Lysing	1.2	0.2	0.0	0.0	1.4	1985
6506/6-1	0.0	37.0	1.1	2.1	41.2	2000
6507/11-6 Sigrid	0.4	1.9	0.3	0.0	2.9	2001
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6608/10-11 S	0.0	0.2	0.0	0.0	0.2	2006
7122/6-1	0.0	7.4	0.0	1.0	8.4	1987
Total	**61.5**	**149.1**	**8.5**	**14.9**	**241.7**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled
3) 6407/6-6 includes resources for 6407/6-7 S - discovery year 2009

(Source: Norwegian Petroleum Directorate)

Table 2.7 Resources in discoveries that have not been evaluated

Discovery	Oil mill. scm	Gas bill. Scm	NGL mill. tonnes	Condensate mill. scm	Oil.equiv. mill. scm o.e[1)]	Year of discovery[2)]
15/12-21	10.0	0.0	0.0	0.0	10.0	2009
15/6-10	0.0	0.6	0.0	0.3	0.8	2009
15/9-B-1	0.0	5.4	0.0	2.6	8.0	2009
16/1-7	0.6	0.1	0.0	0.0	0.7	2004
16/2-3	2.9	0.4	0.0	0.0	3.3	2007
16/2-4	0.3	1.9	0.0	0.0	2.2	2007
16/2-5	0.2	1.9	0.0	0.0	2.1	2009
24/9-9 S	4.0	0.0	0.0	0.0	4.0	2009
25/2-17	4.0	0.0	0.0	0.0	4.0	2009
25/4-10 S	1.0	0.0	0.0	0.0	1.0	2009
25/8-17	0.5	0.0	0.0	0.0	0.5	2009
30/11-7	0.6	3.3	0.0	0.0	3.8	2009
30/5-3 S	0.3	1.5	0.0	0.0	1.8	2009
30/8-4 S	0.2	0.1	0.0	0.0	0.3	2009
34/12-1	1.6	10.7	1.2	0.0	14.5	2008
34/8-13 A	1.2	0.2	0.0	0.0	1.4	2009
35/10-2	0.0	1.6	0.0	0.0	1.6	1996
35/12-2	17.0	2.2	0.0	0.0	19.2	2009
35/3-7 S	0.0	5.0	0.0	0.0	5.0	2009
6407/2-5 S	3.5	1.5	0.0	0.0	5.0	2009
6407/8-5 S	3.1	0.5	0.0	0.0	3.6	2009
6507/3-7	0.0	0.6	0.0	0.0	0.6	2009
6507/3-8	0.0	1.4	0.0	0.0	1.4	2009
6603/12-1	0.0	38.0	0.0	0.0	38.0	2009
6608/10-12	4.4	0.2	0.0	0.0	4.6	2008
6705/10-1	0.0	15.5	0.0	0.6	16.1	2009
6707/10-2 A	0.0	0.6	0.0	0.0	0.6	2008
7120/12-2	0.0	8.0	0.0	0.1	8.1	1981
7120/12-3	0.0	1.8	0.0	0.0	1.8	1983
7222/11-1	0.0	27.2	0.0	2.8	29.9	2008
7226/2-1	0.0	3.3	0.0	0.1	3.4	2008
Total	**55.3**	**133.5**	**1.2**	**6.4**	**197.5**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year the discovery well was drilled

(Source: Norwegian Petroleum Directorate)

Appendix 3 Operators and licensees

The table below lists the operators and licensees in production licences and fields on the Norwegian continental shelf. There are 438 active production licences and 439 operatorships. This is due to the fact that Maersk Oil Norway AS and Statoil Petroleum AS share operatorship in production licence 296. In addition, Gassco AS is the operator for large parts of the gas pipeline network. For more information, please visit our Fact Pages at www.npd.no

Table 3.1 Operators and licensees per March 2010

Operator/licensee	Operatorship in production licence	Licensee in production licence	Licensee in field
A/S Norske Shell	9	23	8
BG Norge AS	15	21	
BP Norge AS	11	15	7
Bridge Energy AS	1	16	
Centrica Resources (Norge) AS	8	21	3
Chevron Norge AS	1	6	1
ConocoPhillips Skandinavia AS	13	38	23
DONG E & P Norge AS	7	31	8
Dana Petroleum Norway AS	3	22	3
Det norske oljeselskap AS	2	21	7
Det norske oljeselskap ASA	37	62	
Discover Petroleum AS	1	12	
E.ON Ruhrgas Norge AS	8	32	2
Eni Norge AS	13	49	19
ExxonMobil Exploration and Production Norway AS	9	53	26
GDF SUEZ E&P Norge AS	4	36	5
Hess Norge AS	2	16	4
Idemitsu Petroleum Norge AS	1	19	7
Lotos Exploration and Production Norge AS	3	11	1
Lundin Norway AS	24	43	3
Maersk Oil Norway AS	2	9	
Maersk Oil PL 018C Norway AS	1	1	
Marathon Petroleum Norge AS	10	15	3
Nexen Exploration Norge AS	9	11	
North Energy AS	1	11	
Norwegian Energy Company ASA	7	38	1
OMV (Norge) AS	7	10	
Petro-Canada Norge AS	2	11	
Premier Oil Norge AS	2	8	1
RWE Dea Norge AS	3	35	8
Repsol Exploration Norge AS	1	3	
Rocksource ASA	3	9	
Statoil Petroleum AS	163	221	64
Talisman Energy Norge AS	17	34	7
Total E&P Norge AS	14	77	41
VNG Norge AS	2	25	2
Wintershall Norge AS	5	14	
Wintershall Norge ASA	18	37	3

Other licensees:	Licensee in production licence	Licensee in field
4Sea Energy AS	2	
Altinex Oil Norway	6	2
Bayerngas Norge AS	16	1
Bayerngas Produksjon Norge AS	10	2
Concedo ASA	9	
Edison International Norway Branch	5	
Enterprise Oil Norge AS	6	7
Faroe Petroleum Norge AS	19	1
Genesis Petroleum Norway AS	6	
Norske AEDC AS	7	2
PGNiG Norway AS	8	1
Petoro AS	147	46
Sagex Petroleum Norge AS	6	
Skagen 44 AS	8	
Skeie Energy AS	8	1
Spring Energy Exploration AS	2	
Spring Energy Norway AS	25	1
Svenska Petroleum Exploration AS	9	2
Talisman Resources Norge AS	3	2

(Source: Norwegian Petroleum Directorate)

Appendix 4 List of addresses

GOVERNMENT BODIES

The Ministry of Petroleum and Energy
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The Norwegian Petroleum Directorate
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Tel. +47 51 87 60 00. Fax +47 51 55 15 71
www.npd.no

The Harstad office
P.O. Box 787, 9488 Harstad
Tel. +47 77 01 83 50. Fax +47 77 06 38 95

The Ministry of Labour
P.O. Box 8019 Dep, 0030 Oslo
Tel. +47 22 24 90 90. Fax +47 22 24 87 11
www.regjeringen.no/ad

The Petroleum Safety Authority Norway
P.O. Box 599, 4003 Stavanger
Tel. +47 51 87 60 50. Fax +47 51 87 60 80
www.ptil.no

The Ministry of Finance
P.O. Box 8008 Dep, 0030 Oslo
Tel. +47 22 24 90 90
www.regjeringen.no/fin

The Ministry of the Environment
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The Climate and Pollution Agency
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Chevron Norge AS
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ConocoPhillips Skandinavia AS
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Dana Petroleum Norway AS
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Det norske oljeselskap AS
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Det norske oljeselskap ASA
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DONG E&P Norge AS
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Eni Norge AS
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E.ON Ruhrgas Norge AS
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www.eon-ruhrgas-norge.no

ExxonMobil Exploration and
Production Norway AS
P.O. Box 60, 4064 Stavanger
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www.exxonmobil.no

GDF SUEZ E&P Norge AS
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Tel. +47 52 03 10 00. Fax +47 52 03 10 01
www.gdfsuezep.no

Hess Norge AS
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Idemitsu Petroleum Norge AS
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Lotos Exploration and Production Norge AS
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www.lotosupstream.no

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Maersk Oil PL 018 C Norway AS
c/o Mærsk Oil Norway AS

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Nexen Exploration Norge AS
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www.nexeninc.com

North Energy AS
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www.northenergy.no

Norwegian Energy Company AS (NORECO)
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Tel. +47 99 28 39 00. Fax +47 51 53 33 33
www.noreco.no

OMV (Norge) AS
P.O. Box 130, 4065 Stavanger
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Petro-Canada Norge AS
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Premier Oil Norge AS
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VNG Norge AS
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Wintershall Norge AS
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Wintershall Norge ASA
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Appendix 5 Conversion factors

Oil. condensate and gas volumes are stated in standard cubic metres (scm) and NGL volumes in tonnes.
A measure of total resources can be obtained by adding up the energy content in the various types of petroleum. The total is calculated in standard cubic metre oil equivalents (scm o.e.).

1 scm oil	=	1.0 scm o.e.
1 scm condensate	=	1.0 scm o.e.
1000 scm gas	=	1.0 scm o.e.
1 tonne NGL	=	1.9 scm o.e.

Gas	1 cubic foot	1 000.00	Btu
	1 cubic metre	9 000.00	kcal
	1 cubic metre	35.30	cubic feet

Crude oil	1 scm	6.29	barrels
	1 scm	0.84	toe
	1 tonne	7.49	barrels
	1 barrel	159.00	litres
	1 barrel per day	48.80	tonnes per year
	1 barrel per day	58.00	scm per year

Approximate energy content

		MJ
1	scm natural gas	40
1	scm crude oil	35 500
1	tonne coal equivalent	29 300

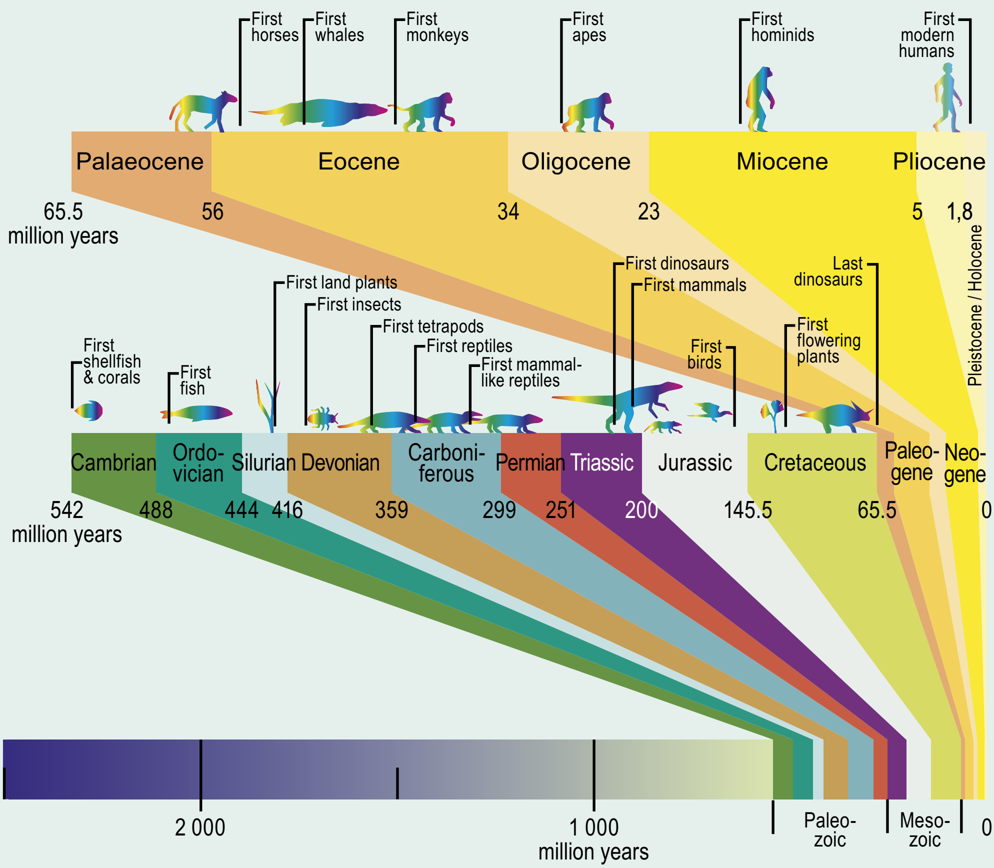
Conversion factors for volume

1	scm crude oil	=	6.29 barrels
1	scm crude oil	=	0.84 tonnes crude oil (average for oil from the Norwegian continental shelf)
1	scm gas	=	35.314 cubic feet

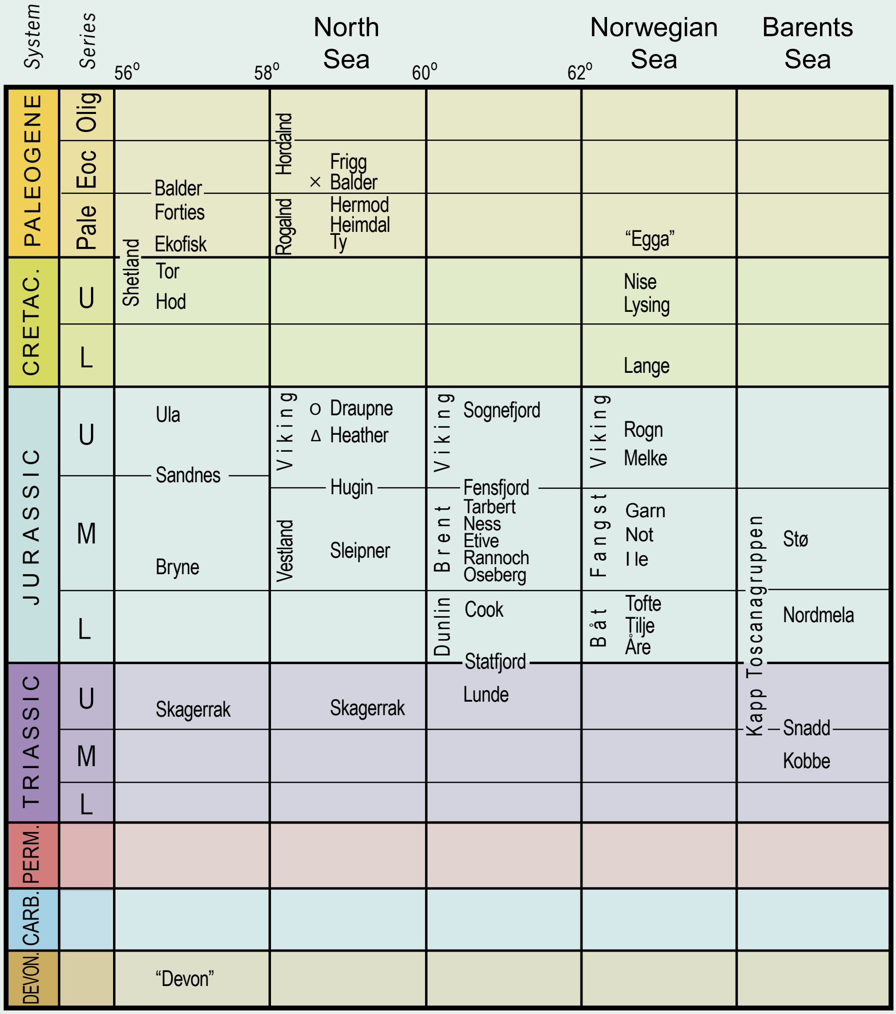
Conversion factors between various units of energy

			MJ	kWh	BTU
1	MJ	Megajoule	1	0.2778	947.80
1	kWh	kilowatt hour	3.6	1	3412.10
1	BTU	British thermal unit	0.001055	0.000293	1

Appendix 6 The Geological Timescale



Appendix 7 Reservoir and Lithostratigraphy



× Balder - intra Balder sandstone
o Draupne - intra Draupne sandstone
Δ Heather - intra Heather sandstone
"Egga" - informal unit

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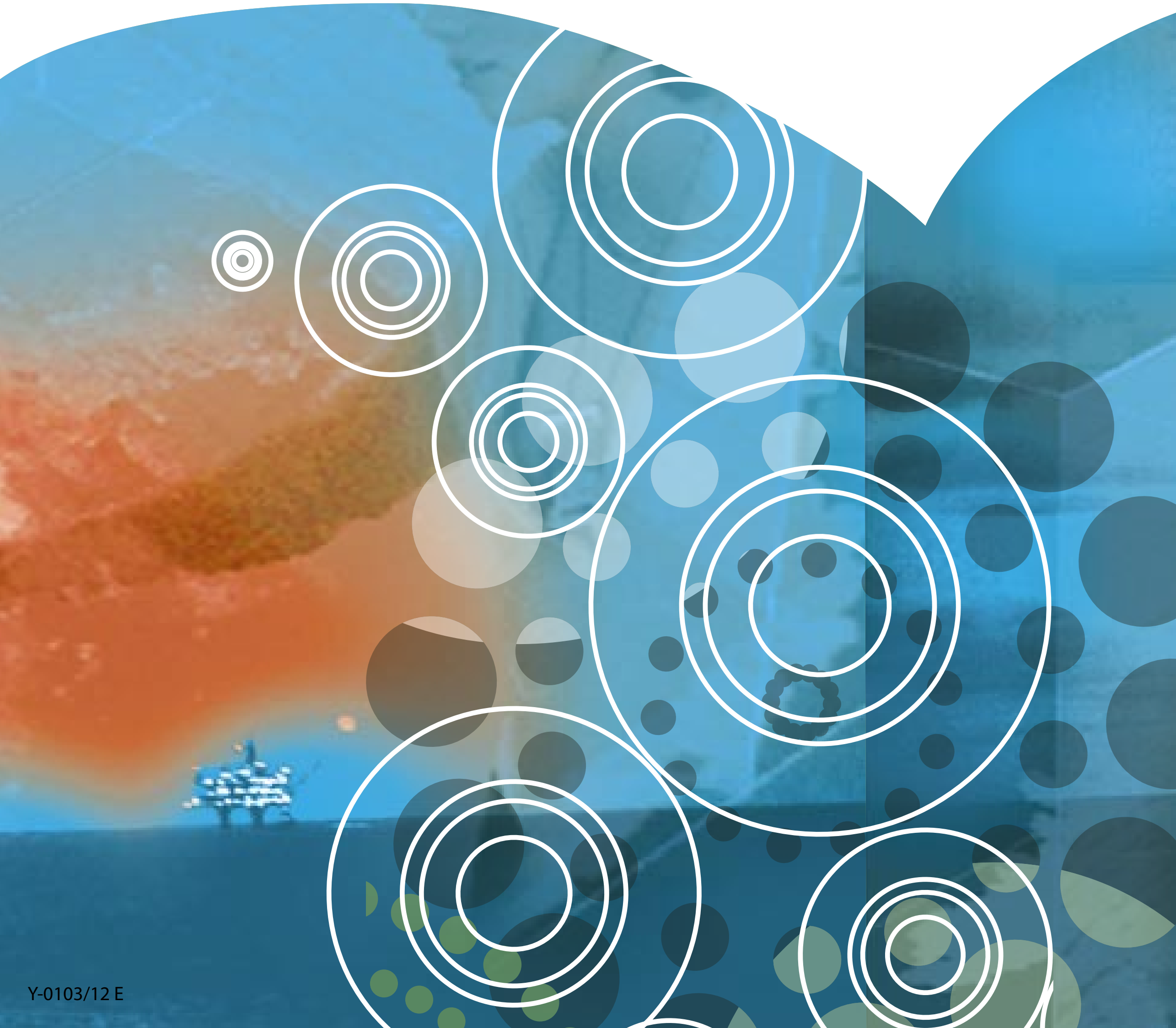

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