FACTS

THE NORWEGIAN PETROLEUM SECTOR

2007

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Ministry of Petroleum and Energy

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Foreword by the Minister of Petroleum and Energy, Odd Roger Enoksen

The level of activity in the Norwegian petroleum sector is currently very high. There is great interest in the Norwegian shelf. The Norwegian supplier industry is competitive and secures major assignments both in Norway and abroad. There are many reasons for this vigorous activity. The high price of oil is a significant factor, while continuing development of technology is also an important contribution to increasing the activity level, in part because improved technology makes it possible to achieve profitable development of more resources. At the same time, the fact that this energetic activity has also led to delays and significant cost increases is a cause for concern.

Exploration activity on the Norwegian shelf increased in 2006 after several years of decline. The number of exploration wells spudded doubled from 2005 to 2006, and the forecasts for 2007 show that the number of exploration wells will continue to rise. The considerable interest shown in the most recent licensing round, which was concluded in February of this year (APA 2006), shows that the exploration acreage on the Norwegian shelf continues to be attractive. Never before have so many production licenses been awarded on the Norwegian shelf. The licensing rounds in recent years also indicate that more and more new players are entering the Norwegian shelf.

The Ormen Lange and Snøhvit fields will come on stream during 2007. These are large fields that will provide a significant contribution to overall Norwegian gas production. At the same time, the fields entail establishment of new infrastructure that can serve future field developments. Snøhvit and Ormen Lange also have major regional and local ripple effects through the development and operation of the fields. The land facilities are being set up to accommodate possible future supply of gas for local and regional use.

Major developments lower the threshold for implementing new and smaller developments in the future because existing infrastructure will be available for use. This is the case for many of the smaller developments on the Norwegian shelf. In other words, the big picture of the activities on the Norwegian shelf is complex. We see another interesting development trend in the plans to develop Frøy and Yme, which both represent new developments of fields that were shut down earlier.

The fact that the future development pattern will increasingly consist of smaller developments and developments linked to existing infrastructure means that effective utilisation of available capacity on existing platforms and other infrastructure is increasingly important. In 2006, the Ministry laid down new regulations relating to use of facilities by others. The purpose of these regulations is to achieve efficient use of existing platforms and pipelines so as to ensure more exploration for and production of petroleum on the Norwegian continental shelf.

In the spring of 2006, the plan for comprehensive management of the marine environment in the Barents Sea and the waters of Lofoten was submitted to the Storting (Norwegian Parliament), which considered the white paper in June 2006. We have thus confirmed stable and predictable framework conditions for the petroleum activities in these offshore areas. Several programs are now underway to strengthen our knowledge regarding these areas before the management plan is revised in 2010. Similar work on a management plan for the Norwegian Sea has also been initiated, with submission to the Storting planned for 2009.

The human contribution to climate change constitutes one of our greatest challenges. Power production and other use of fossil energy is the largest source of greenhouse gas emissions. The Government places great emphasis on capture and disposal of CO_2 from gas power plants as a measure towards reducing CO_2 emissions. On 12 October 2006, the Norwegian State and Statoil entered into an implementation agreement to establish the largest full-scale CO_2 processing facility of its kind at the planned combined heating and power plant at Mongstad.

Minister of Petroleum and Energy

Foreword by Director General Gunnar Berge

2006 was a year of record-breaking gas production on the Norwegian continental shelf, while oil production was lower than expected. Forecasts show that gas production is rising while oil production is declining. The number of exploration wells increased significantly in 2006 compared with the previous year, but only six new discoveries were made. These were made in four wellbores.

This is figures for reflection. If we are to achieve the development that we want, with only a slow and gradual decline, serious efforts must be made in several areas.

More exploration

Although the number of exploration wells doubled from 2005 to 2006, and about 30 exploration wells are expected in 2007, there is every reason to monitor the development closely. The authorities have acted in accordance with a clearly-defined wish by the petroleum industry for more exploration acreage. Now it is the industry's turn to deliver. The Norwegian Petroleum Directorate's estimates show that we have produced and sold about one-third of our petroleum resources so far, while about one-fourth has yet to be discovered. Now it is important that we explore more to find deposits which, even though they may be smaller than the largest discoveries, are still large enough to warrant development. It is also important that we make new discoveries close to fields that are currently in operation, so that the new fields can start producing while the production facilities are still in place.

More people

The lack of capacity can impede sufficient exploration activity. One of the greatest challenges the industry faces in the years to come will be to attract clever brains. We work in a greying industry. Our goal must be that when those who have been in the industry a long time retire, we will have a queue of enthusiastic young people with new ideas and boundless energy, just waiting to take over the reins. There was a contest among young petroleum industry employees, Young Professionals, during the major international oil conference and exhibition, ONS in Stavanger. Their task was to present relevant visions of the future. Four teams from four different enterprises were selected to present their vision of what they view as being the most important challenges in the future. The winning team in 2006 - which I am proud to inform you came from the NPD - pointed precisely to the issue of recruiting as being a major bottleneck. Our young professionals think we must do a better job of communicating how exciting it is to work in this industry - and that this is an industry with many opportunities for the future.

Oil or gas?

Over the next five to ten years, decisions will be made that may have significant consequences for oil production from the Norwegian continental shelf. These decisions deal with the issue of whether the gas resources in the respective fields shall be used as a drive mechanism to increase oil recovery, or whether it is more profitable to sell the gas. Many of the largest oil fields, such as Oseberg, Heidrun, Åsgard, Gullfaks Sør, Snorre and Grane also have substantial gas volumes that are used for injection and pressure support for the oil production. To date, a total of about 490 billion Sm^3 gas has been injected in 28 fields on the Norwegian continental shelf. This gas injection has resulted in a total of more than 200 million Sm^3 of additional oil.

When oil production declines, these fields will face important choices: When should we stop gas injection and turn to full gas export? When the gas is produced without being reinjected, the pressure in the reservoir drops and it becomes more difficult to extract the remaining oil. Therefore, if we sell too much gas too early, significant volumes of oil will be lost. With the development of increasingly better technology, gas injection will probably become more efficient in the future, even when the volumes of oil are small. Therefore, the authorities will make certain that the decisions made regarding gas export are considered very carefully.

Extended lifetime

We see a trend where the expected lifetime for fields is increasing. By making operations more efficient, i.a. through integrated operations, costs can be reduced so that operations are profitable even when production is low. For the largest oil fields, it may even be profitable to build new facilities that are better suited to today's technology and environmental standards.

New development of shutdown fields

There are 13 shutdown fields in the North Sea, most in the Frigg and Ekofisk areas. Some of these fields are now candidates for new production. In this respect, Yme is the first oil field to be redeveloped after production ceased six years ago. The field is located in the south-eastern part of the North Sea and originally produced 8 million Sm^3 of oil. According to the plan, approximately the same volume of oil will be produced from a new production facility scheduled to come on stream from 2009. Talisman is the operator of this new development. This is good resource management and the Norwegian Petroleum Directorate notes that it is the new, smaller oil companies that are active in this area.

Player scenario

More than 40 new oil companies - both large and small - have been prequalified for activities on the shelf after the introduction of the prequalification scheme aimed at attracting new players. The authorities want diversity on the shelf. New companies can contribute new ideas about the best way to exploit the resources. Statoil and Hydro announced plans to merge just before Christmas 2006. It is important to promote robust diversity, not least in light of this planned merger. The new company needs to be challenged, both by other companies and by a stronger NPD.

Gunnar Berge

Director General

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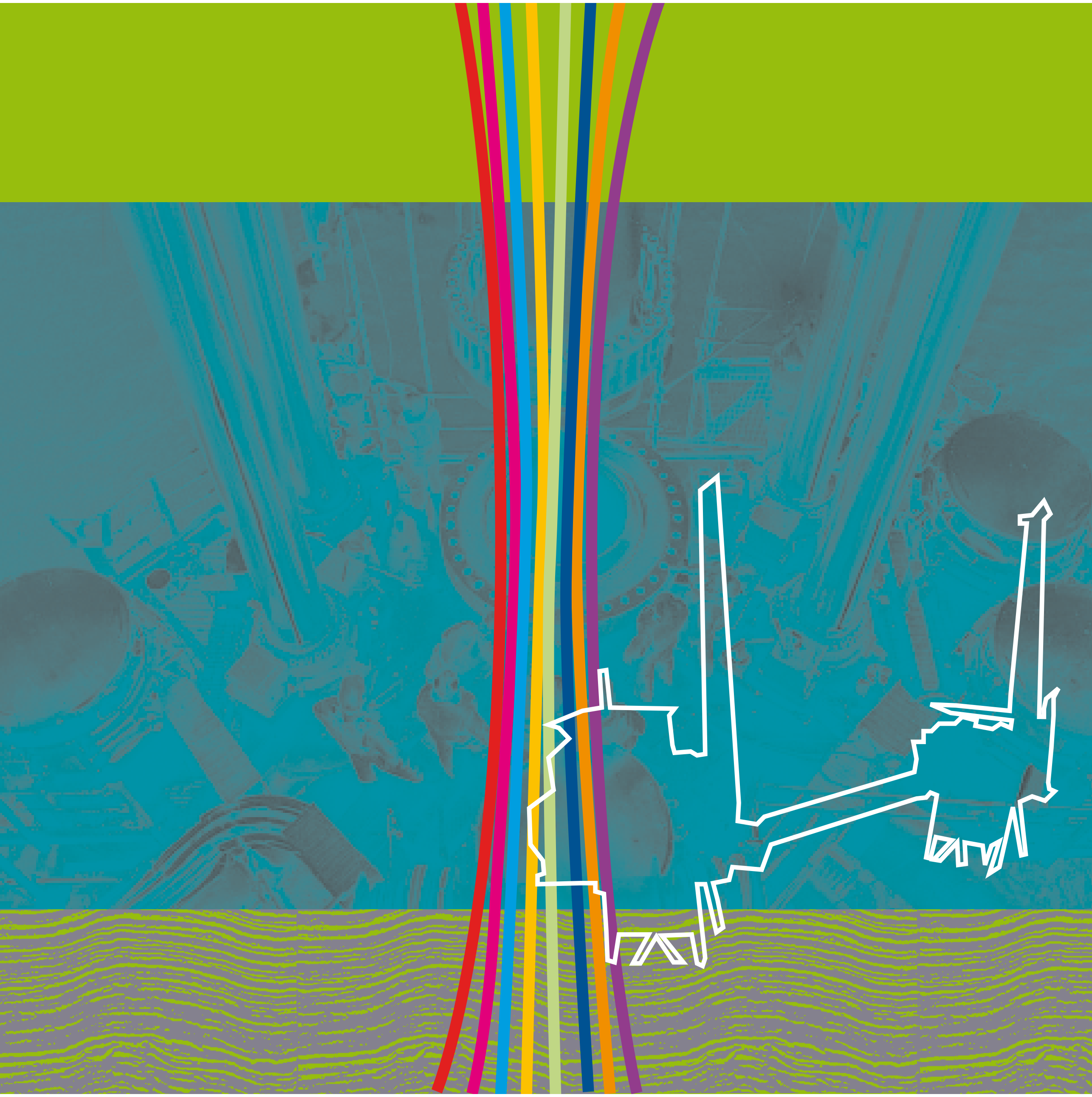
1 The petroleum sector - Norway's largest industry



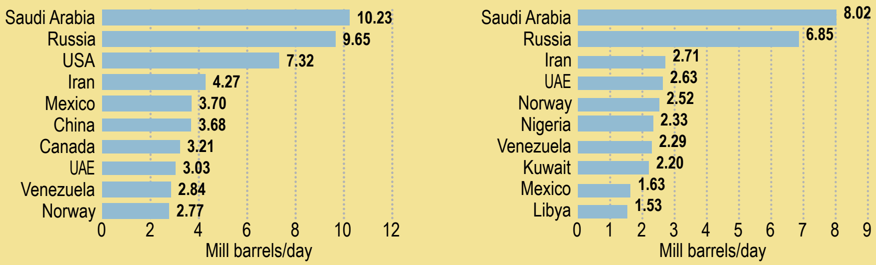


Figure 1.1 The largest oil producers and exporters in 2006 (including NGL/condensate)
(Source: Petroleum Economics Ltd.)

In the late 1950s, very few people believed that the Norwegian continental shelf 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 really began. Production from the field began on 15 June 1971, and in the following years a number of major discoveries were made. Today, there are 52 fields in production on the Norwegian continental shelf. In 2006, these fields produced 2.8 million barrels of oil (including NGL and condensate) per day and 88 billion standard cubic metres (scm) gas, for a total production of saleable petroleum of 249 million scm oil equivalents (o.e.). Norway ranks as the world's fifth largest oil exporter and the tenth largest oil producer, see figure 1.1. In 2005, Norway was the third largest gas exporter and the seventh largest gas producer in the world.

The significance of the petroleum sector in the Norwegian society

Petroleum activities have contributed significantly to economic growth in Norway and to the financing of the Norwegian welfare state. Through nearly 40 years of operations, the industry has created values in excess of NOK 5000 billion in current terms; it is today Norway's largest industry. In 2006, the petroleum sector accounted for 25 percent of value creation in the country. This equals one third the value creation of the manufacturing industry and around 18 times the total value creation of the primary industries.

Through direct and indirect taxes and direct ownership, the state is ensured a high proportion of the values created from the petroleum activities. In 2006, the state's net cash flow from the petroleum sector amounted to approximately 36 percent of total revenues. After more than 30 years of production, the sector has generated net revenues to the state in the order of NOK 3000 billion in current terms. Beyond the resources used to cover the non-oil budget deficit, the state's revenues from petroleum activities are allocated to a separate fund, the Government Pension Fund – Global (formerly the Government Petroleum Fund). By the end of 2006, the value of this fund was NOK 1784 billion.

In 2006, crude oil, natural gas and pipeline services accounted for 51 percent of the value of

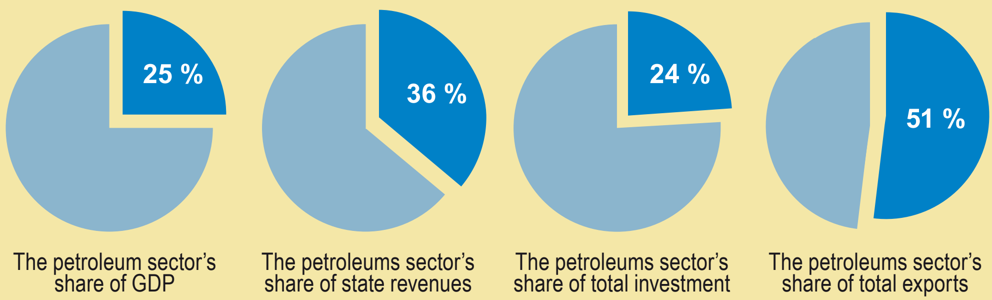


Figure 1.2 Macroeconomic indicators for the petroleum sector
(Source: Statistics Norway, Ministry of Finance)

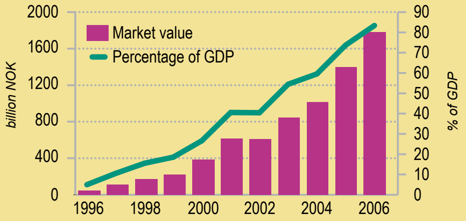


Figure 1.3 The size of the Government Pension Fund - Global at 31.12.2006 and as a share of GDP

(Source: Norwegian Public Accounts, Statistics Norway)

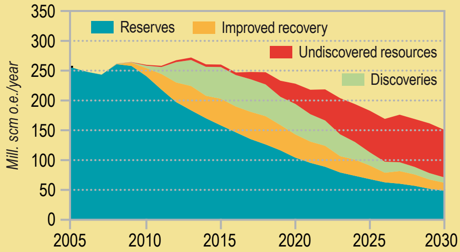


Figure 1.4 Production forecast

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

Norway's exports. Measured in NOK, the value of petroleum exports was 509 billion, 15 times higher than the export value of fish.

Since the petroleum industry started its activities on the Norwegian continental shelf, enormous sums have been invested in exploration, field development, transport infrastructure and land facilities; at the end of 2006 this amounted to approximately NOK 2000 billion in current terms. Investments in 2006 amounted to NOK 95.7 billion, or 24 percent of the country's total real investments.

Future trends

In spite of more than 30 years of production, only approximately 35 percent of the expected total resources on the Norwegian continental shelf have been produced. There is thus potential for further value creation.

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

Oil production is expected to remain steady over the next few years, and to fall gradually thereafter. Gas production is expected to increase from the current level of nearly 90 billion scm, to 125-140 billion scm from 2013. From representing approximately 35 percent of the total Norwegian petroleum production in 2006, 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 level of activity on the Norwegian continental shelf remains high. In 2007, an investment level of NOK 82 billion is anticipated and approximately 30 exploration wells are scheduled for drilling. There will be investment both in measures to increase oil recovery and in developing new fields. The individual projects with the largest investments are Gjøa/Vega, Skarv and Goliat. Investments are expected to increase until 2010, before falling to a somewhat lower level than we have today. Nevertheless, forecasts indicate that activity in the industry will remain high over the long term, see figure 1.5. In the years ahead, investments will relate primarily to modification and drilling activities. There is considerable uncertainty tied to the investment forecasts, for both the longer and the shorter terms. In addition to the investments, the forecasts also reveal a market for operations and maintenance of approximately NOK 40-45billion annually for many years to come.

The oil price is a very important factor as regards the activity level and revenues to the state. The price of oil has increased substantially in recent years, averaging approximately USD 65 per barrel in 2006 (Brent quality). At the beginning of 2007, the price had dropped below

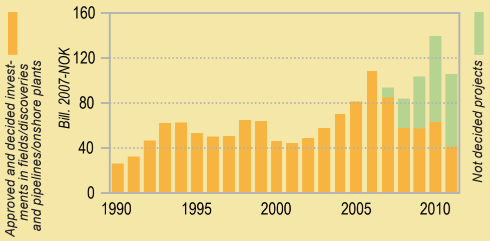


Figure 1.5 Historic investments and forecasted future investments (investments excl. exploration costs)

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

USD 60 per barrel. There are several reasons for the high price level. The world economy has experienced strong growth and although a moderate slowing of this growth is expected in the future, this indicates that the demand for oil will remain high. Available production capacity worldwide is low, with increased vulnerability to interruptions in production. If the world economy continues to grow, there is reason to believe that oil prices will remain at a relatively high level in the years to come.

2 Norwegian resource management

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, official 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 for Norway in developing its petroleum activities was to establish a system of managing the petroleum resources that would contribute to maximising the values for the Norwegian people and the Norwegian society.

To begin with, the Norwegian government selected a model in which foreign companies carried out all petroleum activities on the Norwegian continental shelf. Over time, the Norwegian involvement was strengthened through the participation of Norsk Hydro in the activities, and by the creation of a wholly owned state oil company, Statoil[1]. A private Norwegian company, Saga Petroleum, was also established, but was later acquired by Norsk Hydro[2]. 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 is 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

1 Statoil was listed on the stock exchange in 2001. The Norwegian state currently owns 70.9 percent of the Statoil shares.

2 In December 2006, Statoil and Norsk Hydro announced a plan to merge Statoil with Norsk Hydro's oil and gas activities. The companies intend to implement the merger during the course of the third quarter of 2007.

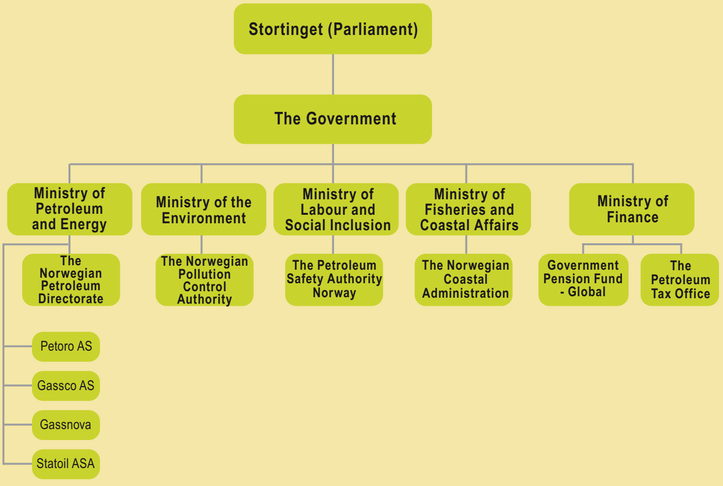


Figure 2.1 National organisation of the petroleum sector

(Source: Ministry of Petroleum and Energy)

be predictable and transparent. This is the general basis for the incentive system Norway has established on the Norwegian continental shelf. 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 the Norwegian society as a whole. At the same time, consideration for the external environment, health, work environment and safety plays an important role.[3]

Norwegian and international oil companies are responsible for the actual conduct of 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 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, in connection with exploration drilling[4], plans for development and operation[5] and decommissioning plans[6] for fields. In this system, the oil companies create the necessary technical solutions to recover the resources, while the Norwegian authorities ensure that these solutions concur with the goal of maximising the values for the Norwegian society as a whole.

For the oil companies to fill the function of maximising the values on the Norwegian continental shelf, a framework must be in place which provides the petroleum industry with incentives to fulfil 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[7]. At the same time, however, tax deductions are granted for the costs associated with petroleum activities. In such a tax system, the Norwegian State functions as a passive owner in a production licence on the Norwegian continental shelf. This system implies that, if the oil companies do not make money, the Norwegian State will not collect revenues. 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 authorities as a main rule award production licences to a group of companies instead of one company alone. Production licences are normally awarded on the basis of applications from oil companies in connection with licensing rounds[8]. The most important criteria for award include understanding the geology, technical expertise, financial strength and the experience of the oil company. Based on the applications, the Ministry of Petroleum and Energy establishes a licensee group. 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

3 *Environmental considerations in the petroleum activities are addressed in Chapter 9*

4 *Ref. Chapter 3.*

5 *Chapter 4 addresses development and operation, while gas management is discussed in Chapter 5.*

6 *More on decommissioning after production is concluded in Chapter 6*

7 *Ref. Chapter 8.*

8 *A more detailed discussion of exploration policy can be found in Chapter 3.*

the value in the production licence they have been awarded. Under this system, expertise and experience from around the world are gathered together in nearly all of the production licences on the Norwegian continental shelf. 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[9].

National organisation of the petroleum sector

The Storting

The Storting, the Norwegian parliament, establishes the framework for Norwegian petroleum activities. The methods used include passing legislation and adopting propositions, as well as discussing and responding to white papers concerning the 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:

- The Ministry of Petroleum and Energy
  – responsible for resource management and for the sector as a whole
- The Ministry of Labour and Social Inclusion
  – responsible for health, 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.

KonKraft and the Senior Management Forum

The Ministry of Petroleum and Energy works in close dialogue with the Norwegian-based oil and gas industry to strengthen competitiveness on the Norwegian continental shelf, as well as the competitiveness of the supply industry.

This process has been termed KonKraft. To ensure that KonKraft has sufficient professional clout, an arena has been set up where the industry and the authorities can discuss key challenges and proposals for concrete measures. This arena is called the Senior Management Forum (Toppleiarforum). The Senior Management Forum was established in the autumn of 2000 and is chaired by the Minister of Petroleum and Energy. The Forum is composed of about 40 senior managers from oil companies, the supply industry, employees' and employers' organisations, research institutes and the authorities.

9 *See Chapter 7.*

More on the national 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 mandates given by the Storting and the government. The Norwegian Petroleum Directorate is administratively subordinate to the Ministry of Petroleum and Energy. In addition, the Ministry holds a particular responsibility for monitoring the state-owned companies, Petoro AS, Gassco AS and Gassnova, and the partly state-owned Statoil ASA.

The Norwegian Petroleum Directorate

The most important tasks for the Norwegian Petroleum Directorate are to maintain the administrative and financial control of exploration and recovery of the petroleum resources, in order to ensure that such exploration and recovery is in accordance with legislation, regulations, decisions, licence conditions and the guidelines laid down by the Ministry. The Directorate is an advisory body for the Ministry in questions regarding the petroleum sector.

Petoro AS

Petoro AS is a state-owned company which is responsible for 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.

Gassnova

Gassnova is an administrative agency with the task of promoting and supporting innovation and development of environmentally friendly gas power technology.

Statoil ASA

Statoil ASA is listed on the Oslo and New York stock exchanges. The state owns a 70.9 percent share in the company. In December 2006, Statoil and Norsk Hydro announced plans to merge Norsk Hydro's oil and gas activities with Statoil. The companies plan to implement the merger during the course of the third quarter of 2007. Based on the companies' proposed terms, the state will own 62.5 percent of the shares in the company. The state's objective is to increase its ownership share to 67 percent over time.

More on the national organisation of the petroleum sector

THE MINISTRY OF LABOUR AND SOCIAL INCLUSION
The Ministry of Labour and Social Inclusion holds the overall responsibility for the work environment and for safety and contingency measures in relation to the petroleum sector.

The Petroleum Safety Authority Norway
The Petroleum Safety Authority Norway has regulatory responsiblity for safety, contingency measures and the work 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 and other revenues from the petroleum sector.

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 a correct assessment and collection of the taxes and fees that have been determined by the political authorities.

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

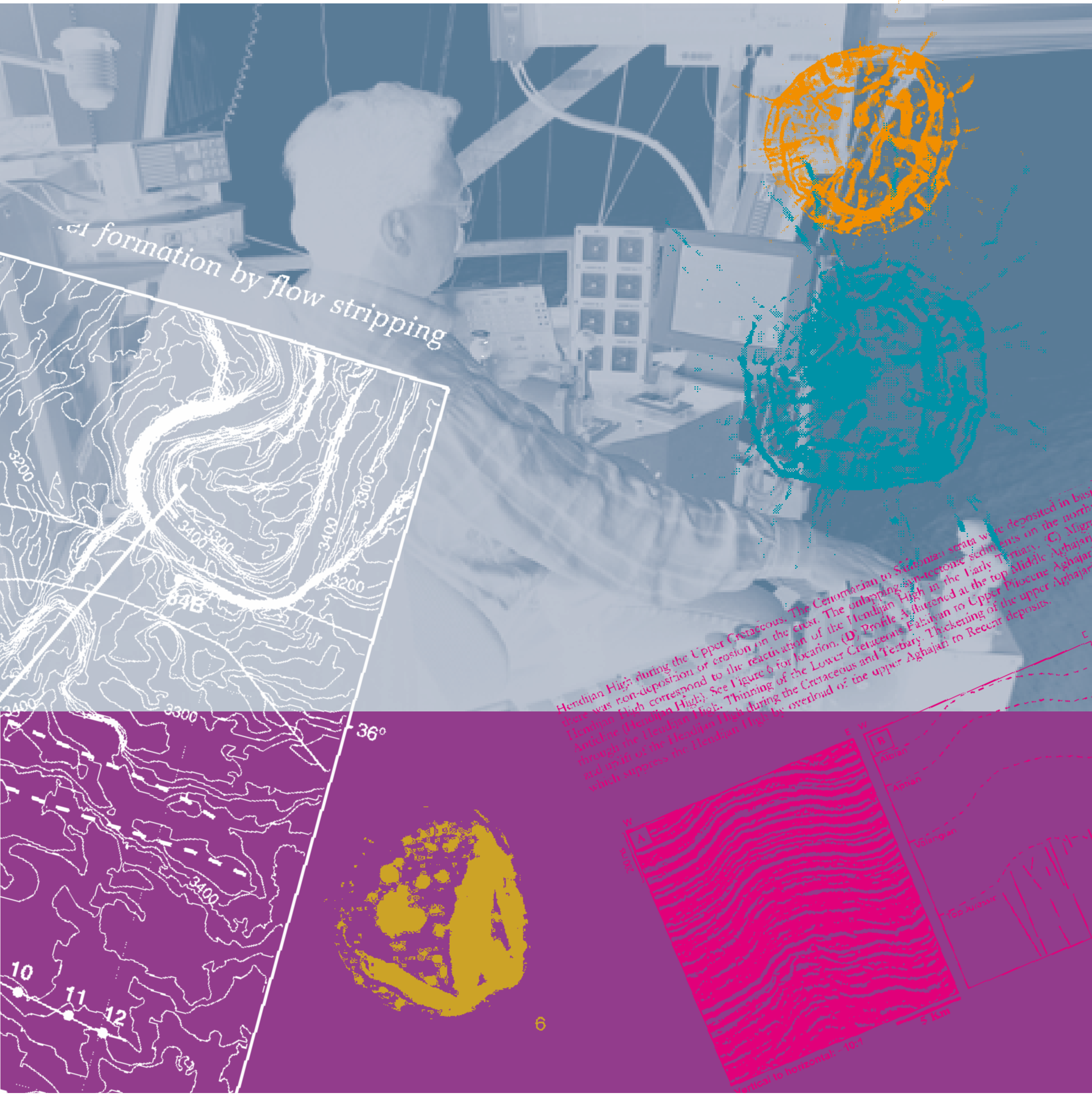
THE MINISTRY OF FISHERIES AND COASTAL AFFAIRS
The Ministry of Fisheries and Coastal Affairs is responsible for maintaining adequate contingency measures against acute pollution in Norwegian waters.

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

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

The Norwegian Pollution Control Authority
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, and technical documentation.

3 Exploration activities



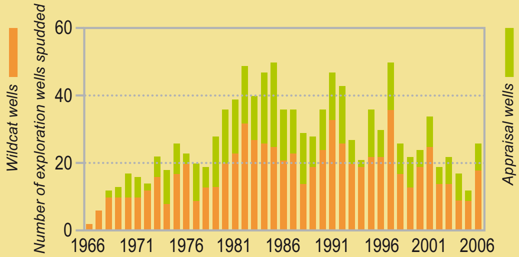


Figure 3.1 Exploration wells spudded on the NCS 1966-2006

(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. The framing of exploration policy is hence an important aspect of Norwegian resource management.

In recent years there has been a trend towards less exploration activity on the Norwegian continental shelf than was previously the case and fewer major discoveries have been made. However, exploration activities increased in 2006 compared with 2005, and a further increase in exploration activities is expected in 2007. For the authorities, it is important that Norwegian exploration policy provides for rapid and efficient identification of new resources. It is the companies which then undertake the exploration itself and the proving of new resources. Exploration policy is therefore designed to increase the attractiveness of the Norwegian continental shelf and to help bring in new players to complement the existing ones. The authorities seek to promote a correct level of activity on the continental shelf through the structure of the licensing system and through access to and management of exploration acreage.

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 of 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 proprietary right to subsea petroleum deposits on the Norwegian continental shelf is vested in the state. Before permission for exploration drilling and production (a production licence) can be awarded, the area in question must have been opened up for petroleum activities. An impact assessment, covering such aspects as the environmental, economic and social effects of such activities on other industries and adjacent regions, must be carried out.

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 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. This document supplements the provisions of the Petroleum Act and specifies detailed terms for each licence. The licence provides an exclusive right for exploration, exploration drilling and the

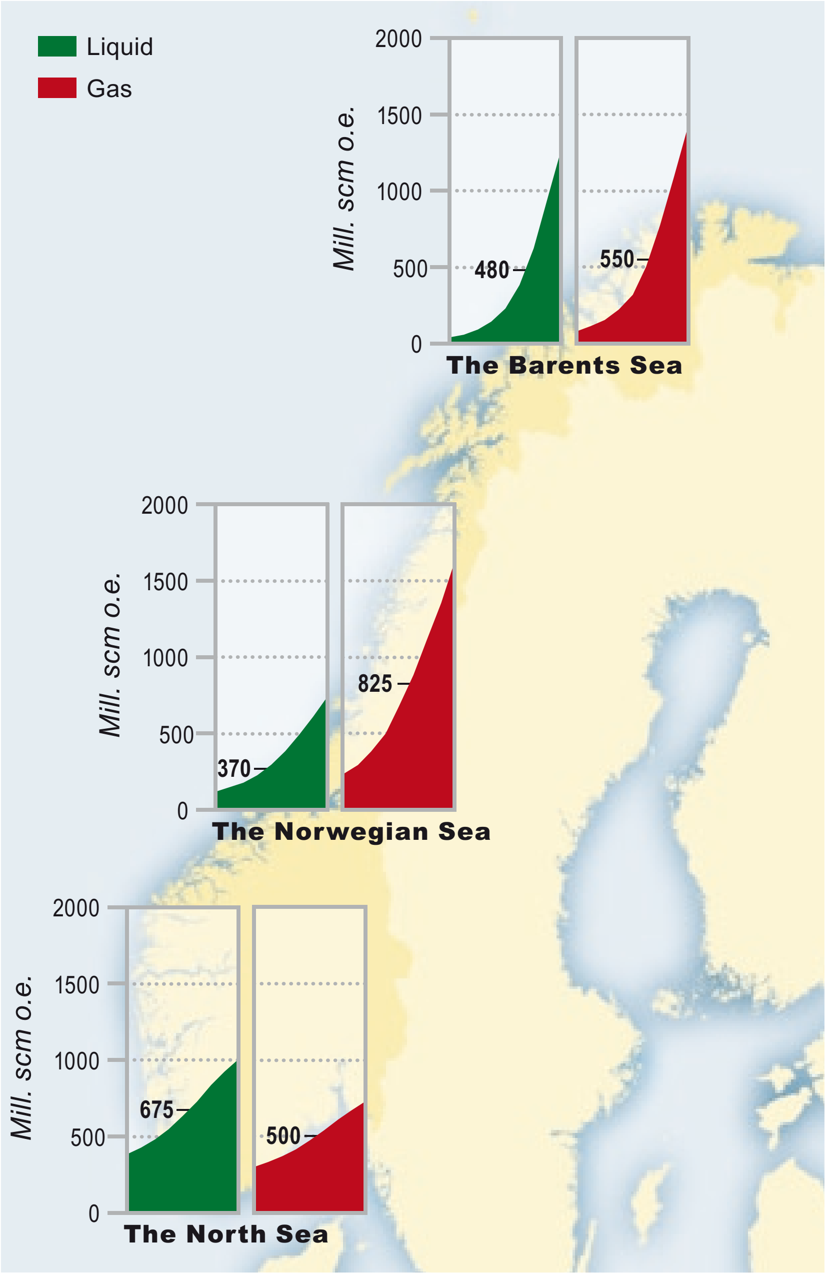


Figure 3.2 Undiscovered resources by area. The figure in each bar shows expected recoverable volume while the uncertainty in the estimate is shown by the curved line, low estimate to the left, high estimate to the right.
(Source: Norwegian Petroleum Directorate)

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 exploration period, which can last up to ten years. A specified work obligation must be met during this period, including seismic surveys and/or exploration drilling. Providing that all the licensees agree, a licence can be relinquished once the work obligation has been fulfilled.

Mature and frontier areas

The parts of the Norwegian continental shelf that the Parliament has opened up for petroleum activities are the greater part of the North Sea, Norwegian Sea and the southern Barents Sea. The Norwegian Petroleum Directorate's estimate of undiscovered resources in the areas on the continental shelf totals 3.4 billion standard cubic metres (scm) of recoverable oil equivalents. This is slightly less than the volumes that have already been produced to date on the Norwegian continental shelf and the resources are divided more or less equally between the three regions, with 35 percent in the North Sea, 35 percent in the Norwegian Sea and 30 percent in the Barents Sea. Depending on the degree of maturity of the different areas, there is some variation in the types of challenges faced in realising the commercial potential of the undiscovered resources on the Norwegian continental shelf.

Characteristics of mature areas include familiar geology and well-developed or planned infrastructure. In these areas it is often rewarding to drill small prospects. At the same time, however, 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.

In frontier areas the geology is less known and infrastructure is not established. In some of these areas there are often significant technical challenges. The uncertainty surrounding exploration activity is greater here, but there is still the possibility of making substantial new discoveries in these areas. Players who are capable of exploring for such resources must have broad-based experience and technical, geological expertise and have a solid financial base. The distribution of undiscovered resources is shown in figure 3.2.

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 infrastructure is overall 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 carry a stand-alone development of infrastructure.

The authorities have determined that industry access to larger parts of 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 prede-

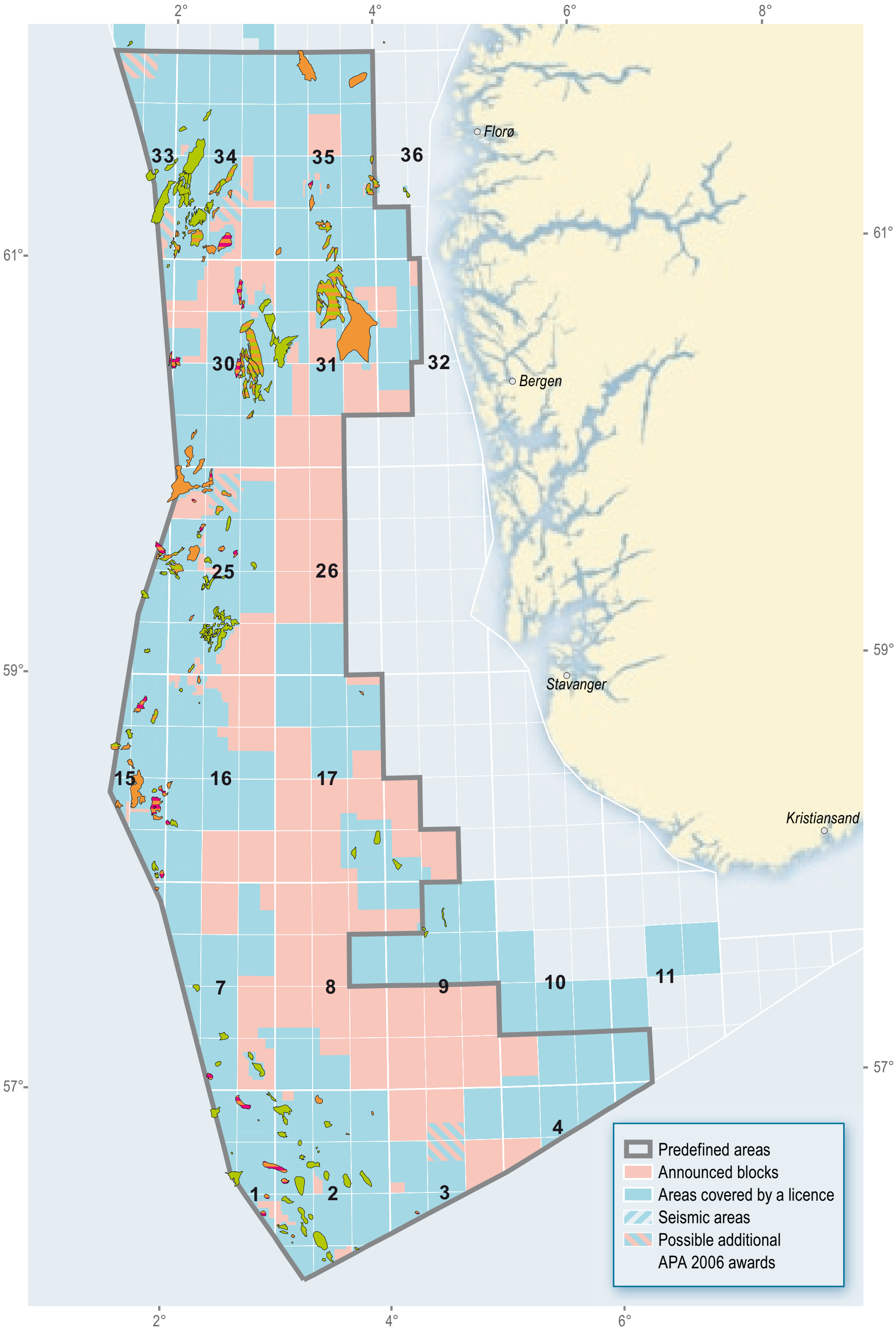


Figure 3.3 Awards in predefined areas - North Sea announcement 2007

(Source: Norwegian Petroleum Directorate)

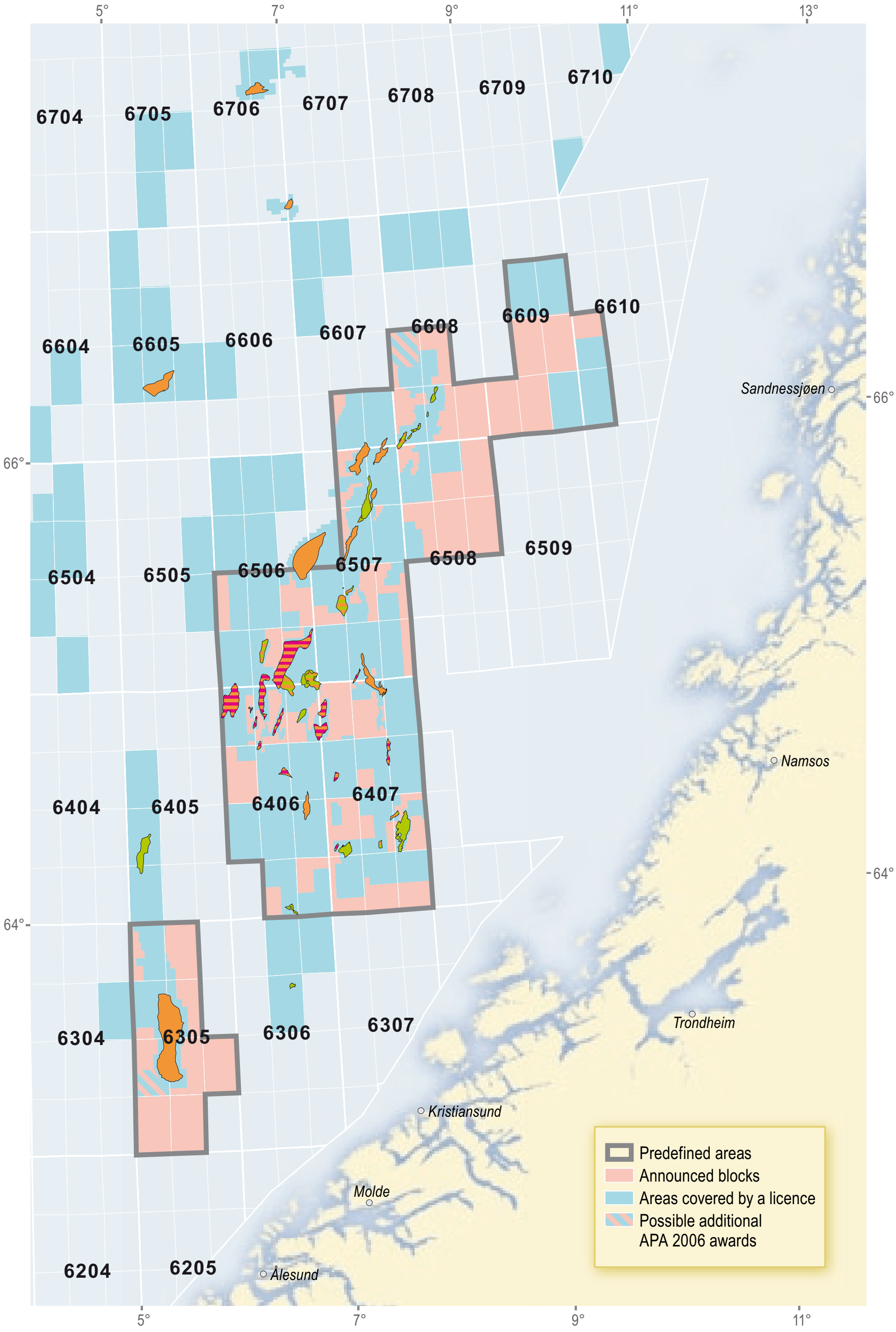


Figure 3.4 Awards in predefined areas - Norwegian Sea announcement 2007

(Source: Norwegian Petroleum Directorate)

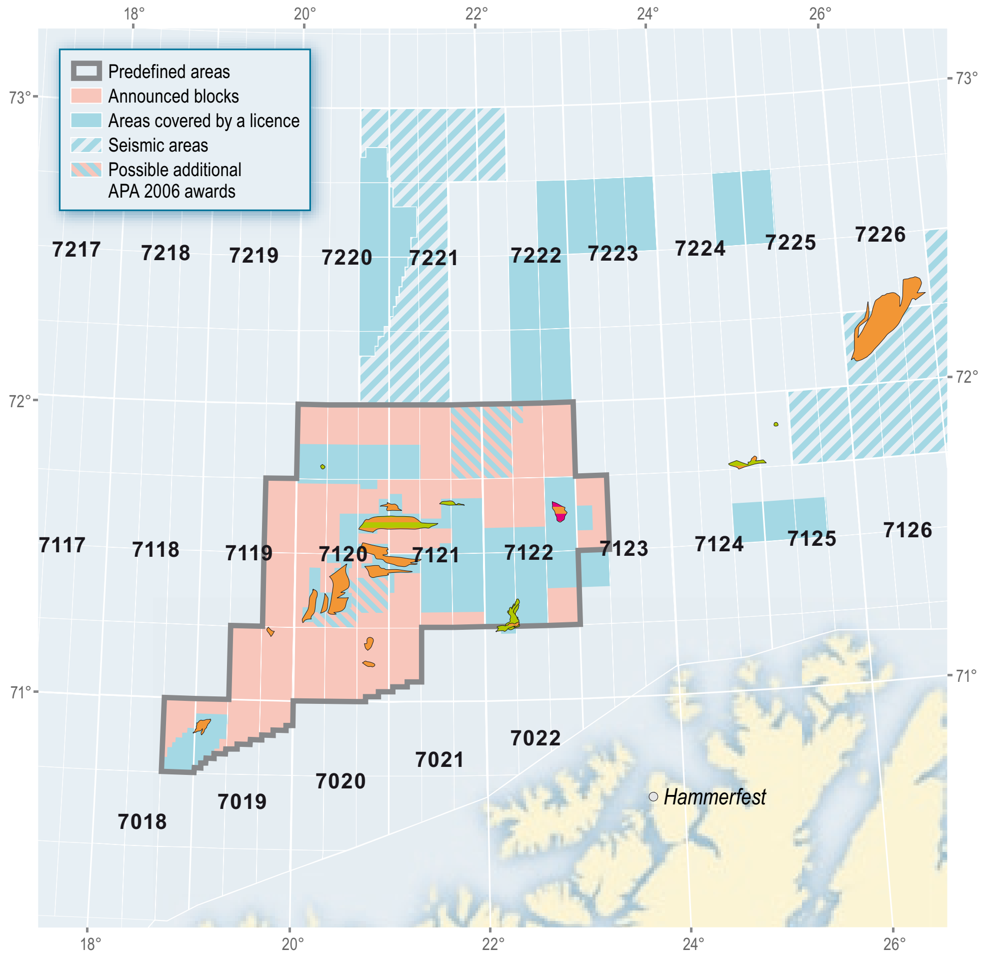


Figure 3.5 Awards in predefined areas - Barents Sea announcement 2007
(Source: Norwegian Petroleum Directorate)

fined areas (APA) in mature areas of the Norwegian continental shelf. The premise 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. Four such licensing rounds have been carried out in mature areas to date: APA 2003, APA 2004, APA 2005 and APA 2006. Figures 3.3, 3.4 and 3.5 show the areas announced for award in APA 2007.

Acreage within the predefined area which is relinquished during the period of time from the announcement of area until the application deadline expires will be included in the announced area. This means that all acreage that is relinquished within the predefined area will automatically be included in the announced area as of the date when the relinquishment takes effect. This will provide an opportunity for other companies who may have a different opinion concerning the area's prospectivity to explore the area quickly. This will ensure more rapid circulation of acreage, and more efficient exploration of the mature areas.

Frequent awards and more announced area in each licensing round have resulted in an increase in licensed area. At the beginning of 2005,

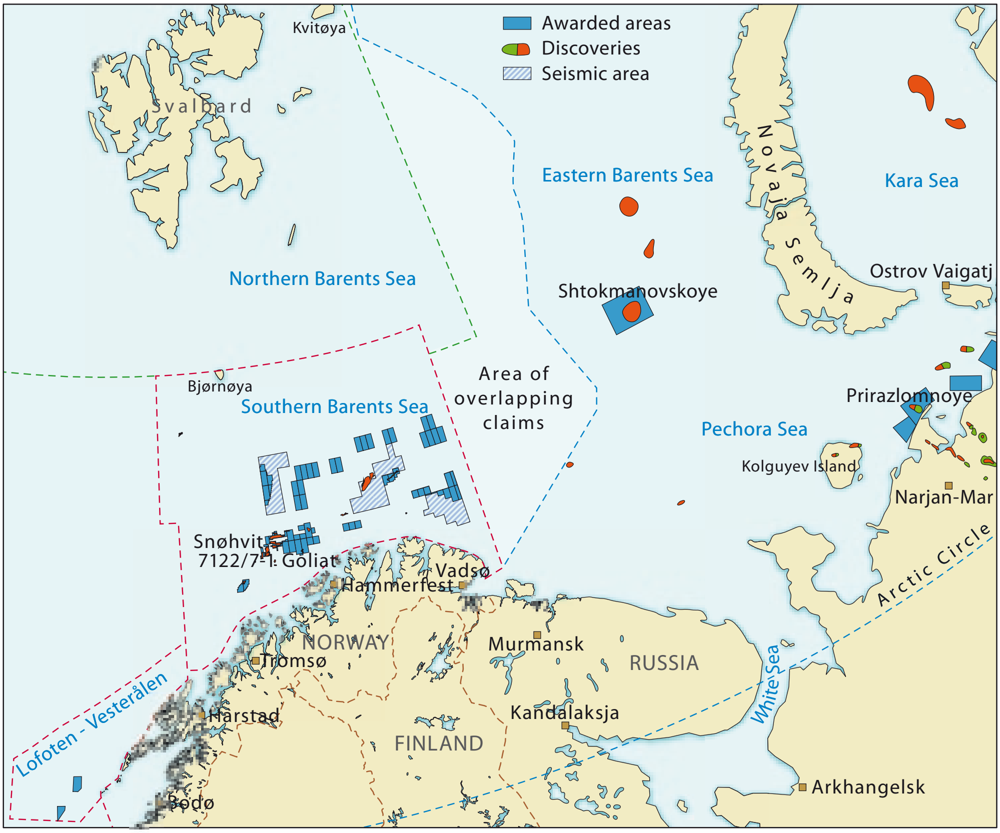


Figure 3.6 Norwegian and Russian part of the Barents Sea
(Source: Norwegian Petroleum Directorate)

22 per cent of the area opened up to petroleum activities on the Norwegian continental shelf was covered by production licenses, an increase from nine percent two years ago.

Active exploration within licensed area is important to the authorities. This requires framework conditions designed to ensure that companies which have been awarded production licences do not leave the area idle, but rather actively explore it.

In the mature areas, the work obligations assumed when companies are awarded new production licences are organised as 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.

Another important change is that the area of the production licence to be awarded is now “tailored” in the sense that the company is only awarded acreage for which it has concrete plans.

Changes have also been made concerning which areas the companies are allowed to retain upon expiration of the initial period. Previously, when the initial period was expired, the companies could retain as much as 50 percent of the awarded area without obligation to carry out any specific activity. Today, the basic rule is that companies

Aker Exploration	Dong	Idemitsu	OER*	
Aker Maritime*	E.ON Ruhrgas	Kerr McGee	OMV	
Altinex	Edison	Lasmo*	Oranje Nassau	Revus
Anadarko	Endeavour	Lundin	PA Resources	Rocksource
BG Norge	Ener	Marubeni	Paladin*	Serica
Bridge Energy	Enterprise*	Mitsubishi	Pelican*	Sumitomo
Centrica	Faroe-Petroleum	Mærsk	Pertra	Talisman
CNR	GdF	Nexen	Petoro	VNG
Discover	Genesis	Noble	Petro-Canada	Wintershall
DNO	Hunt Oil	Noreco	Premier	

*Companies that no longer exist as individual companies

Figur 3.7 Prequalified/new companies since 2000 (As of 1st Quarter 2007)

(Source: Ministry of Petroleum and Energy)

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. In the initial period in which exploration activity proceeds according to a compulsory work programme, the licensees pay no fee. 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 intensified in order 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.

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 principle change in the rules for relinquishing area. The regulations that apply in mature areas will now also apply to the frontier areas. However, it is not expedient for all companies that receive production licenses in frontier 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 delimitation of resources proven through drilling. Futhermore, the same changes apply to frontier 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. The awards represented an important step towards exploring these areas. The plan was to announce the 20th licensing round in 2007; however, this has been postponed until 2008 with award of production licenses in 2009. This postponement will allow use of the results from a number of ongoing exploration wells in the formulation of the next licensing round. The risk of drilling dry wells will be reduced, and the principle of gradual, cost-effective exploration activity will be safeguarded. The gradual exploration strategy for frontier areas has ensured a high discovery rate on the Norwegian continental shelf

The announcement of the 19th licensing round in 2005 includes blocks in both the Norwegian Sea and the Barents Sea. Representative key blocks have been selected for announcement in the Barents Sea, and exploration within these blocks will provide important information about large areas in this ocean territory.

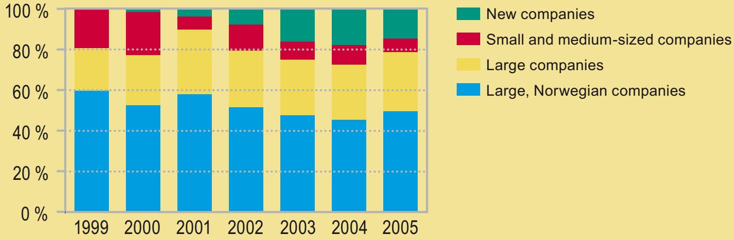


Figure 3.8 Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies
(Source: Norwegian Petroleum Directorate)

It is still possible to make large new discoveries in the frontier areas of the Norwegian continental shelf. The prospects of making such discoveries help ensure that the Norwegian continental shelf remains competitive in an international perspective. 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.

In 2002, consideration for the environment and fishery industry led to the initiation of a study on the consequences of year-round petroleum activity in the Lofoten-Barents Sea area (abbreviated ULB). Based on the results of this study, the government in office resolved not to open areas for further petroleum activities in awarded areas in Nordland VI off the Lofoten coast. At the same time, the government approved a general opening for further year-round petroleum activities in previously opened areas in the southern Barents Sea, except areas with particular environmental or fishery value.

In the winter of 2003, the Ministry of Petroleum and Energy and the Ministry of Fisheries (today: the Ministry of Fisheries and Coastal Affairs) established a working group (Coexistence Group I), with the objective of assessing the possibilities of coexistence between the fisheries and the petroleum industry in the area from Lofoten and northwards, including the Barents Sea. The Ministry of Petroleum and Energy, the Ministry of Fisheries and Coastal Affairs, the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Institute of Marine Research, the Norwegian Fishermen's Association and the Norwegian Oil Industry Association all participated in this work. The group proposed recommended conditions for the regulation of the relationship between petroleum activities and fishery activities in the Barents Sea. The working group summarised its findings in a report completed in July 2003.

The coexistence group resumed its work in the spring of 2005 with a continued discussion of coexistence between petroleum and fishery activities within the frame of sustainable development (Coexistence Group II). In accordance with the Storting (Norwegian Parliament) resolution, the group was expanded to include participants from the Ministry of Environment, the Norwegian Pollution Control Authority, the Directorate for Nature Management and the Norwegian Foundation for Nature Research. The Ministry of Labour and Social Inclusion and the Petroleum Safety Authority Norway were also added to the group.

The report from the Coexistence Group II constituted expert input in relation to Storting White Paper No. 8 (2005-2006) "Comprehensive management plan for the marine environment in the Barents Sea and the waters off Lofoten" (Integrated Management Plan), which was submitted to the Storting in the spring of 2006.

In the fall of 2006, the Coexistence Group II commenced a review of the environmental and fishery conditions for petroleum activities in the Norwegian Sea and the North Sea. The plan is for the group to submit a report prior to the summer of 2007.

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 the Nordland coast and Skagerrak.

The Storting must decide to open these areas for petroleum activities before they can be announced in a licensing round. Such 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.

The present coalition government's position paper, the so-called "Soria Moria declaration", states that "no petroleum activities will commence in Nordland VI during the current parliamentary period". The Integrated Management Plan also gives guidelines for where petroleum activities shall take place. Several programs are now underway to gather more knowledge about the marine area before the Integrated Management Plan is revised in 2010. These programs include a three-year effort for which the Norwegian Petroleum Directorate is responsible aimed at collecting seismic data. A total of NOK 70 million has been allocated to this programme in 2007.

Area with overlapping claims

The border between Norway and Russia remains unclear and is currently being negotiated by Russian and Norwegian authorities. This area, approximately equivalent to the Norwegian part of the North Sea, is marked on figure 3.6.

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 small in number, but 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. Several of these players have been smaller companies with particular expertise in mature areas and tail-end production. 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 web page: www.npd.no/reports.

Prequalification

In order to facilitate the entry of new players, White Paper No. 39 (1999–2000) to the Storting introduced a system for prequalification of new operators and licensees. From the scheme's inception to January 2007, 47 companies had been prequalified, 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 3.7 shows prequalified/new companies on the Norwegian continental shelf since 2000.

Significant acreage and production licences have been awarded to these new players in the North Sea Rounds and APA. In the past three years (up to and including 2005), new players have accounted for more than 15 percent of the exploration costs associated with these rounds.

4 Development and operations

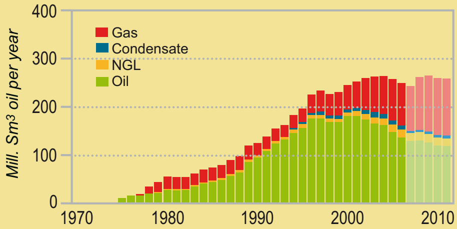


Figure 4.1 Historical production of oil and gas, and expected production for the next few years

In 2006, Norwegian oil and gas production totalled 248 million standard cubic metres (scm). Of this, natural gas production accounted for about 87 million scm, making 2006 a record-breaking year for natural gas production. Natural gas sales are expected to increase further in 2007 to more than 90 million scm, with additional increases expected in the years to come. The natural gas share of total petroleum sales is expected to increase from 35 per cent in 2006 to 45 per cent in 2011. Figure 4.1 shows historical production of oil and gas, and expected production for the next few years.

At the end of 2006, there were 44 producing fields in the North Sea and eight producing fields in the Norwegian Sea. One new field, Ringhorne East, has come into production in 2006. In 2007, seven new fields are expected to start producing; Alvheim, Blane, Enoch, Ormen Lange, Snøhvit, Vilje and Volve. With the Snøhvit field coming on stream, petroleum will also be produced from the Norwegian sector of the Barents Sea. As the Norwegian petroleum industry has moved northwards, it has entered into areas containing enormous gas resources. Consequently, a number of gas fields have been developed and a comprehensive gas transport infrastructure has been established, which has made it possible to develop additional gas resources. Development of the gas fields, combined with falling production from major oil fields, entails that gas is becoming an ever more important component of Norway's petroleum production.

Production on the Norwegian continental shelf has been dominated by a few large fields. Production from several of these fields is on the decline, 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. 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 Norwegian continental shelf. The large fields have contributed to the establishment of infrastructure that subsequent fields have been able to tie into.

Effective production of petroleum resources

To protect society's interests in 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 the 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 petroleum industry framework conditions, companies are obliged to carry out prudent development and operations 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 environmental impact assessment which interested parties are given the opportunity to comment upon in a hearing round. The impact assessment is to describe the development's expected impact on the environment, any transboundary environmental effects, natural resources, fisheries and society in general. The

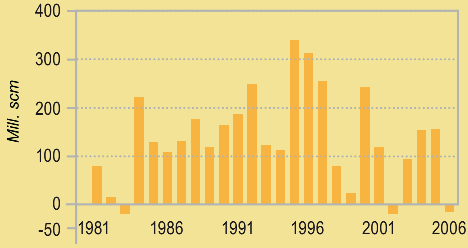


Figure 4.2 Gross reserve growth, oil 1981-2006

(Source: Norwegian Petroleum Directorate)

governmental 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.

Development of proven petroleum resources is the basis for production and value creation from the petroleum industry today, but the importance of exploiting the resources in the known areas is increasing. This constitutes an enormous potential that can generate significant values for society if it is 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 (five billion barrels) oil before 2015. This is equivalent to twice the original oil resources in the Gullfaks fields. 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 4.2 shows annual growth of oil reserves in the period 1981–2006. After an impressive increase of 154 million scm of new reserves in 2005, the accounts for 2006 show a slight decrease of 18 million scm.

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 4.3 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

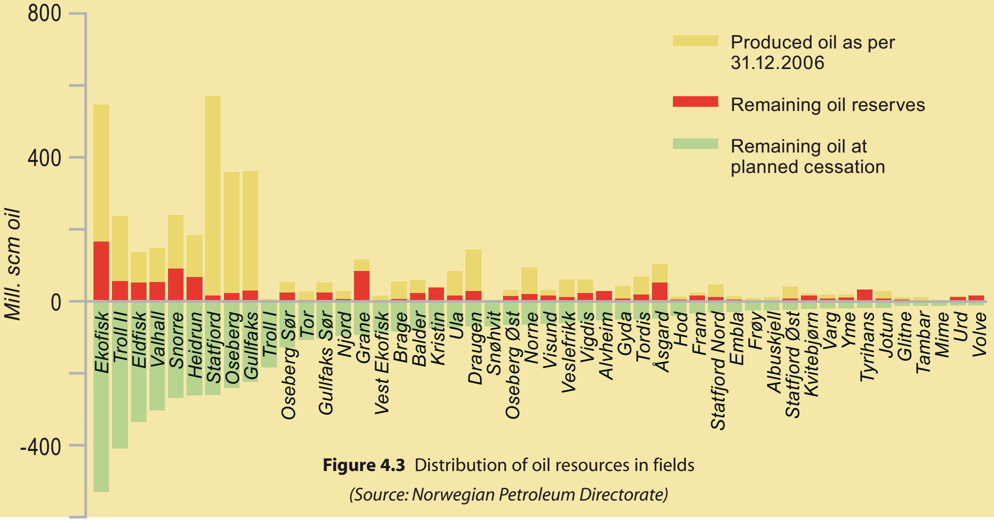


Figure 4.3 Distribution of oil resources in fields

(Source: Norwegian Petroleum Directorate)

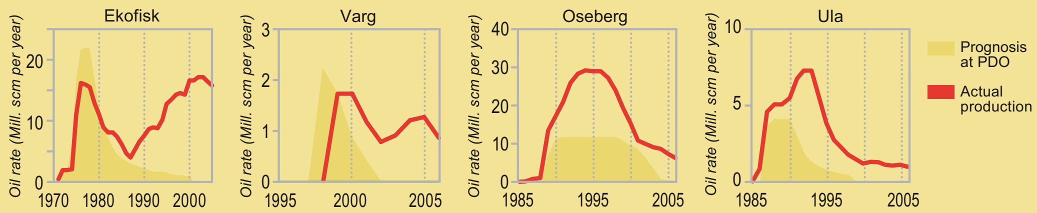


Figure 4.4 Production trends for the Ekofisk, Varg, Oseberg and Ula fields
(Source: Norwegian Petroleum Directorate)

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 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. There is significant and continuous activity underway in this area. These types of measures contribute to increasing the average recovery rate. In 1995, the average recovery rate for oil in producing fields was approximately 40 percent - today it is 46 percent. 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 4.4 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 4.4 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 existing infrastructure, as discussed in the following section.

Figure 4.5 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 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 challenges as regards emissions to air and discharges to sea. 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 because 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

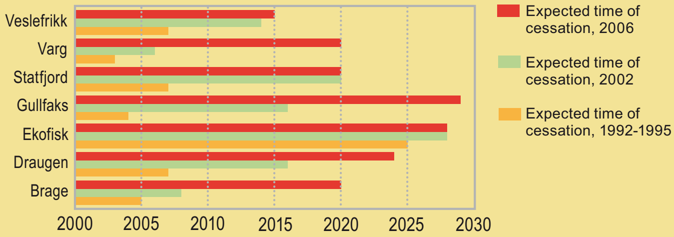


Figure 4.5 Lifetimes of selected fields

(Source: Norwegian Petroleum Directorate)

cost level must be reduced in order to justify profitable operations at a lower production level.

In 2006, the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate introduced a new, more structured monitoring of fields currently in operation. The background for this initiative is that the development towards a more mature shelf also brings about new challenges for the authorities. So far, much of the activity on the Norwegian continental shelf has been directed towards development of large, new fields. The considerable resource potential we see in fields in operation and in the area surrounding existing infrastructure means that there is a need to change the way the authorities follow up the activities in these fields. The goal is to ensure recovery of as much of the resources as possible. Based on data reported by the operators, the authorities conduct an annual benchmark analysis of development in mature areas, called PIAF. This analysis forms the basis for how the authorities will prioritise the follow-up of each field.

Developments in communications technology have given rise to new working methods. This is referred to as integrated operations, eOperations or smart operations. Integrated operations 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. Technology and knowledge are linked in such a manner that it will change the way tasks are assigned between offshore and land, oil companies and supplier firms. Therefore, reduced costs and integrated operations are elements that help streamline operations, and thus increase recovery. See the text box on integrated operations for more information.

New discoveries – effective use of infrastructure

In 2006, NOK 100 billion was invested on the Norwegian continental shelf. Total investments on the Norwegian continental shelf have now reached about NOK 2000 billion in current monetary value. This is equivalent to more than NOK 1 billion each week over the whole period. These investments have made it possible to establish extensive infrastructure which is a condition for making it possible to produce and market 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 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 sector on the Norwegian continental shelf have entered a more mature phase. Of a total of eleven approved development plans (PDOs) in 2005, eight are satellite developments. 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, 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.

Diversity of players

In order to ensure that the potential in and in the surroundings of producing fields 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 on transfers of participating interests. In addition, the authorities have opened up for a broader range of players; reference made to the discussion of new players in Chapter 3. Other countries in which the petroleum sector has reached a mature phase have experienced that established companies do not always prioritise activities in fields where production has fallen to a low level. They would rather sell, to the benefit of companies for which such activity is a core business area. With this in mind, the Norwegian authorities believe that a diversity of players, making various assessments and priorities, constitutes a positive contribution towards realising the resource potential on the Norwegian continental shelf.

Increased recovery, increased 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 oftentimes 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.

Integrated operations on the Norwegian continental shelf

Introduction of integrated operations in the petroleum activities entails using (near) real-time data as a tool for integrating the work associated with different operations. This makes it possible to integrate operations between various disciplines, between operators and suppliers and between work done offshore and on land. Integrated operations will facilitate faster and better management in all phases of the activities. 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 cables) have already been laid to many of the fields on the Norwegian continental shelf. Transmission of large volumes of data from the installation to land is a fundamental prerequisite for integrated operations.

When field data is available in real-time to relevant technical groups, the organisation on land can provide more efficient assistance in the form of support, monitoring and management. Increased safety, better access to expertise and enhanced efficiency in the activities are all important effects. Various players see substantial economic gains arising from integrated operations. A precondition for this is that integrated operations are implemented quickly.

Maximum benefit can be derived from the digital infrastructure with solutions that provide predictable access for third parties, cost-sharing and adequate information security. In order to benefit from all of the possibilities and to realise the potential inherent in integrated operations, changes must be made in work methods and the distribution of tasks between offshore and land and between operators and suppliers. The changes create new organisational structures and link individuals and organisations more closely, regardless of physical location.

Production optimisation and better wells are often listed as key benefits of integrated operations. Most progress has been made in implementing the new forms of operation within drilling. Here players have started to integrate real-time data between operations control rooms on land and on the offshore facilities. Information and necessary data is available to all parties at the same time. This provides better and faster operational support to the offshore personnel, and also facilitates optimal location of wells in the reservoir. The major operators have already documented significant economic benefits derived from these solutions. Links can also be established with control rooms in other locations around the world, thus ensuring better exploitation of special expertise.

Further development

Integrated operations have already become an important element in many new developments. The 2006 annual status reports from the operators indicates 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.

Suppliers, oil companies and research institutions all carry out research and development within these fields. The technical solutions are largely in place, while some work remains as regards development of organisations and work processes.

More research and development is still needed in order to convert data into useful information and knowledge, such as the development of advanced sensors that are reliable over time, and the development of improved data transmission from the wells. Organisational solutions must also be developed that provide the necessary integration across technical disciplines and regardless of geographic location, as well as between various service companies and oil companies.

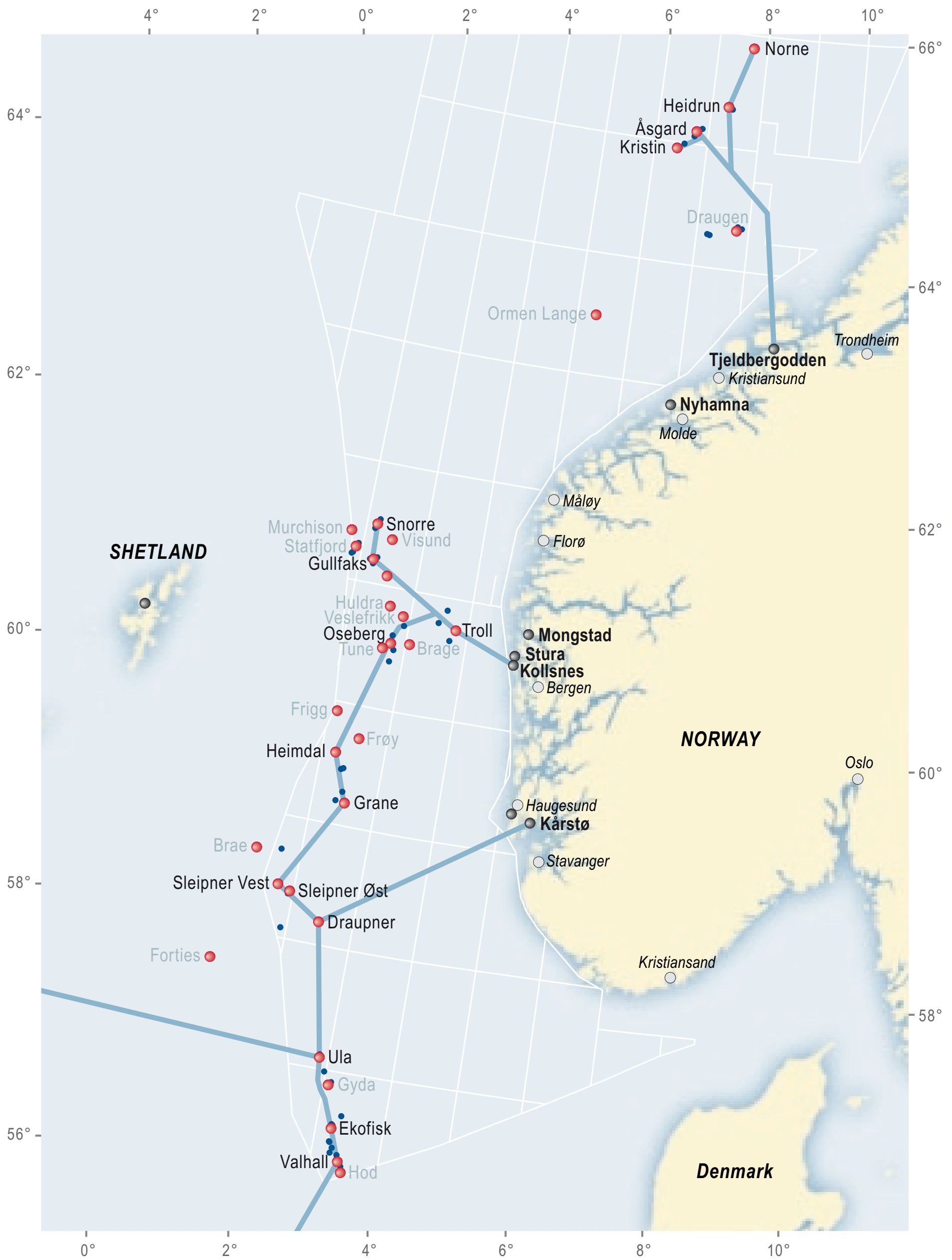


Figure 4.6 Optical fiber cables on the Norwegian continental shelf (Source: Norwegian Petroleum Directorate)

5 Norwegian gas exports

Gas activities comprise an increasing part of the petroleum sector, and thus bring considerable revenues to the state. Norwegian gas is also important for supply of energy in Europe, and is exported to all of the major consumer countries in Western Europe. In terms of energy content, gas exports in 2006 were more than seven times larger than normal Norwegian production of electricity. Norwegian gas exports meet approximately 15 percent of the European gas consumption. Most Norwegian exports go to Germany and France, where Norwegian gas supplies around 30 percent 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, Poland and Denmark. When Snøhvit commences operation in 2007, Norway will also supply LNG (Liquefied Natural Gas) amongst others to the USA.

Current capacity in the Norwegian pipeline system is 100 billion standard cubic metres (bcm), which will increase to 120 bcm when the Langeled pipeline has been completed. Langeled will have a total capacity equivalent to one-fifth of the United Kingdom's gas consumption. 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 figure 5.1). The Norwegian gas transport system is extensive and, following completion of the northern part of Langeled in October 2007, will consist of a network of 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, so that attempts must be made to achieve the optimum balance between oil and gas production. At the same time, 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 instruction concerning marketing and sale of oil and gas.

One special feature of gas production is that it requires major investment 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 investment in the transport system. In many cases, it may be appropriate to build the pipelines somewhat larger than initially needed, so that any 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 3 and 4). Many fields on the Norwegian continental shelf contain both gas and oil. When awarding gas production licences, the authorities take into account optimum recovery of oil. On occasion, the authorities have awarded licences for production of less gas than applied for by the companies, out of consideration for the need to produce oil.

1 *OECD Europa, source: IEA, Natural Gas Information, (2006).*

Figure 5.1 Gas pipelines

(Source: Norwegian Petroleum Directorate)

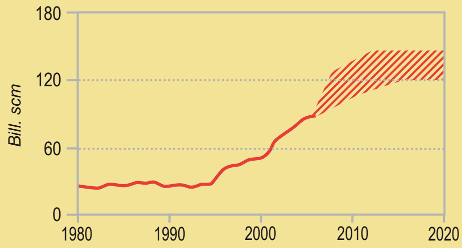


Figure 5.2 Historic and expected Norwegian gas exports . Norwegian gas sales are expected to reach a level between 125 and 140 bill. scm within next decade.
(Source: Norwegian Petroleum Directorate/Ministry of Petroleum and Energy)

The authorities play an important part in establishing transport capacity and increasing system capacity. The authorities are responsible for studying alternative transport methods, in order to ensure that the system develops efficiently. At the same time, it is important to ensure efficient operation, including achieving economies of scale. The 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 coordinated ownership Gassled and regulated conditions for access to the transport system. Use of these instruments is assessed in connection with development of new infrastructure and when the use of the existing infrastructure is changed. Operatorship, ownership and questions 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 holistic further development of the Norwegian gas infrastructure. In cases where major developments are considered, this means that Norwegian gas in addition to those fields that trigger transport needs must also be taken into consideration. Further development of the gas infrastructure must also 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 that all users of the system are treated equally, both in regard to making use of the system and to the 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 conflicts of interest about which pipeline should be used to transport the gas can be avoided.

Regulated access to the transport system

The pipeline system is a natural monopoly, requiring enormous initial investments. This is why

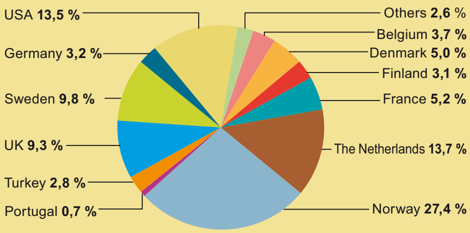


Figure 5.3 Sale of NGL/condensate 2006 by country of first destination
Total 23,3 mill. scm oe
(Source: Norwegian Petroleum Directorate)

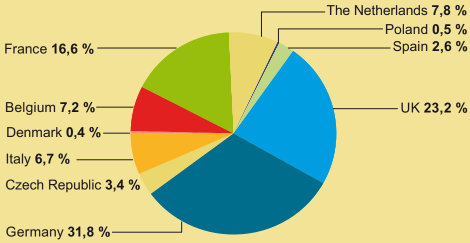


Figure 5.4 Norwegian natural gas exports 2006
Total 86,2 bill. scm
(Source: Norwegian Petroleum Directorate)

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 transportation 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.

Gassled – overall ownership structure for gas transport

The ownership split in Gassled:

Petoro AS*	38.25%
Statoil ASA	20.18%
Norsk Hydro Produksjon AS	11.62%
Total E&P Norge AS	8.09%
ExxonMobil Exploration and Production Norway AS	5.30%
Norske Shell Pipelines AS	4.14%
Mobil Development Norway AS	4.27%
Norsea Gas AS	2,84%
Norske ConocoPhillips AS	1,95%
Eni Norge AS	1,57%
A/S Norske Shell	1,12%
Dong E&P Norge AS	0,07%

* 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 8,4 percent with effect from 1 January 2011, and the other licensees' shares will be adjusted at the same date. The SDFI share in Norsea Gas AS is 40.0 percent. When this is taken into account, the state, represented by SDFI, will have a share in Gassled of 39.4 percent in 2003-2010 and 47,5 percent from 2011. The licence period for most of 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.

6 Decommissioning

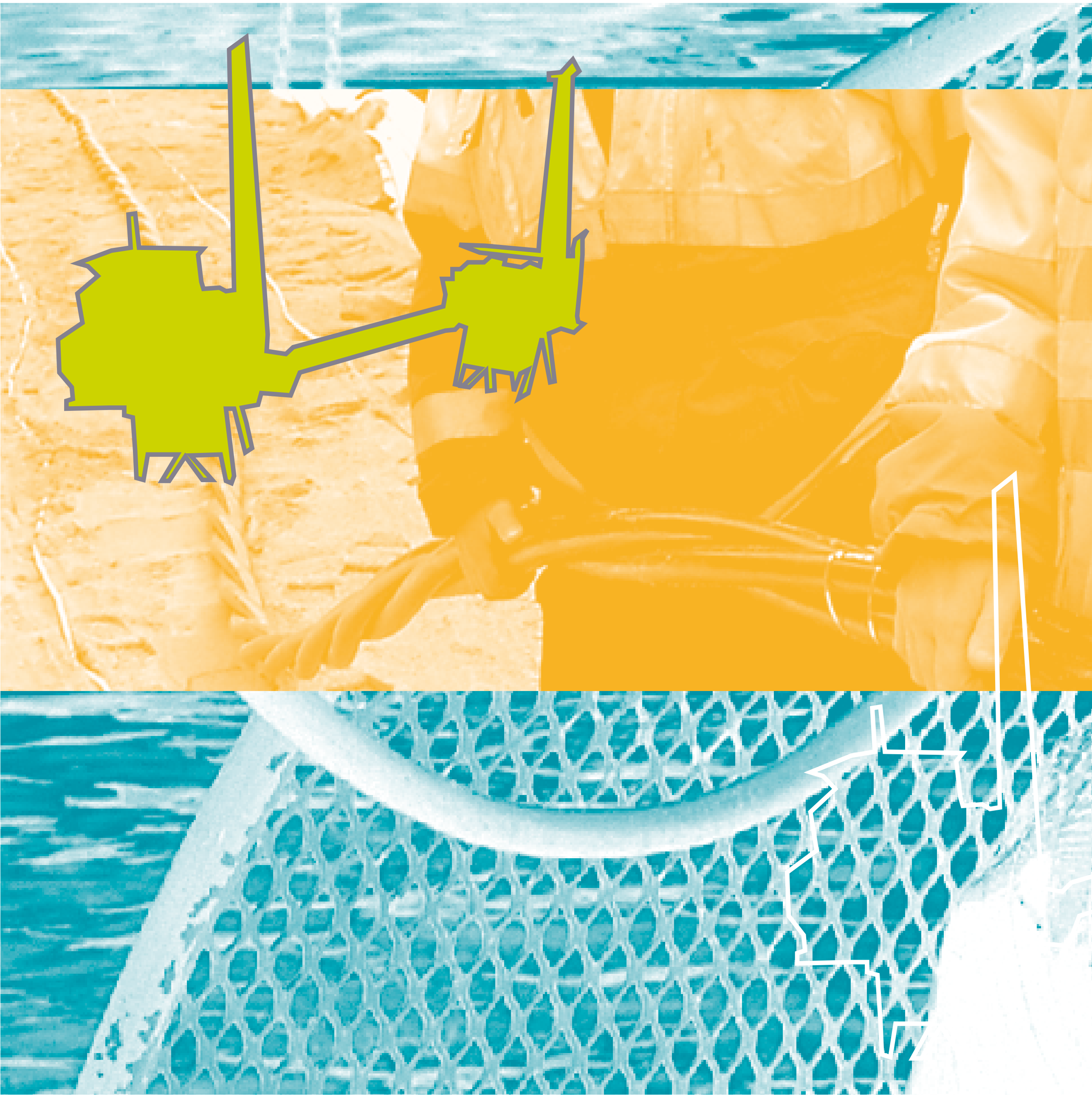


Figure 6.1 Drilling and production installation DP2, to be removed from the Frigg field *(Source: Total E&P Norge AS)*

Petroleum activities only borrow the sea, and all phases of 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 10 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, TOGI and H7. 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. The decommissioning plan for MCP-01 is currently being considered by the Ministry.

The regulations

Both national and international regulations apply to the disposal of an installation on the Norwegian continental shelf.

Disposal or decommissioning of facilities is regulated by the Petroleum Act. 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 to the OSPAR decision concerning disposal on land. As mentioned, permission has been granted to leave in place the Ekofisk Tank and its protective wall, as well as the concrete substructure TCP2 at the Frigg field.

The guidelines laid down in White Paper No. 47 (1999–2000) "Decommissioning of redundant pipelines and cables" to the Storting 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

A principal provision of the legislation 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 and Social Inclusion (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.

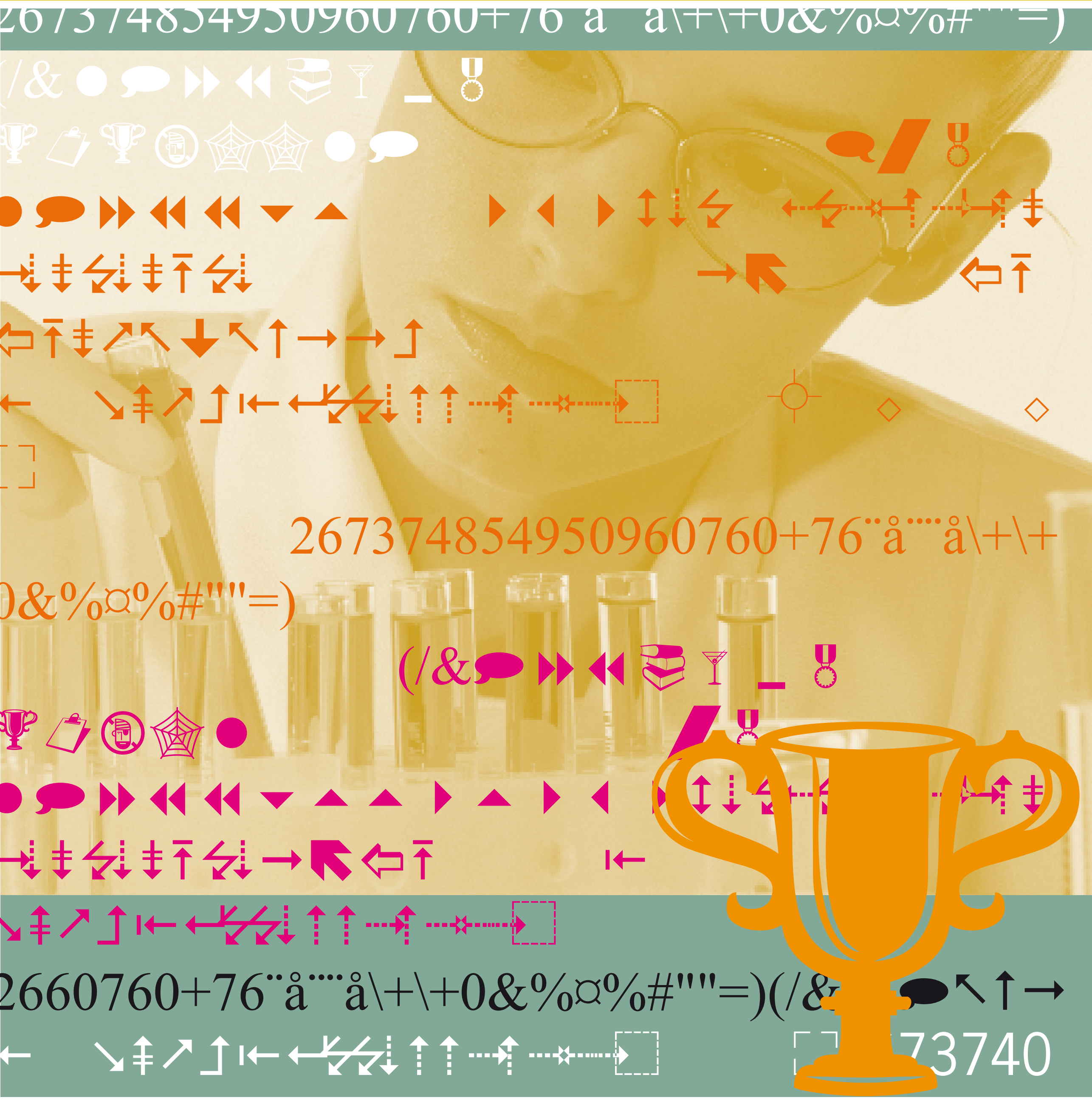
Liability

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.

Figure 6.2 Illustration of the Ekofisk Tank before and after removal of the topsides

(Source: ConocoPhillips)

7 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 to the oil companies, the supply industry and the research institutions. The sector also provides valuable input to innovation and technological development in other sectors of Norwegian business and industry.

Supply companies in Norway are represented in most steps of the value chain, from exploration and development to production and disposal. Norwegian suppliers are among the leading in the world in fields such as seismic survey, drilling equipment, subsea facilities and floating production solutions. These supply companies 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. In 2006, approximately 80,000 people were employed in the petroleum sector in Norway.

Investments by oil companies in development, operation and maintenance on the Norwegian continental shelf generate a considerable demand for products and services from the supply industry in Norway and abroad. In order to stimulate the continuation of this growth, the supply companies must continue their expansion into the international arena. International experience and participation in international development projects are extremely important for the further development of the supply industry. This international experience could also

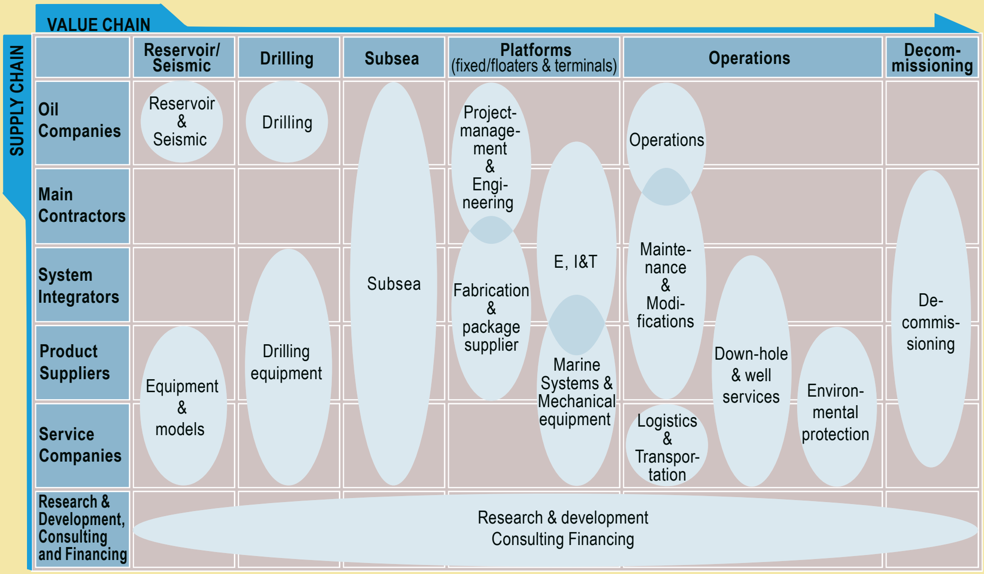


Figure 7.1 Interactive map of the Norwegian Oil & Gas "World-Class" Clusters

(Source: www.Intsok.com)

help reduce the cost level on the Norwegian continental shelf.

Industry and industrial cooperation linked to the petroleum industry

There are a number of arenas and meeting places which promote co-operation in the petroleum industry and improve the players' wider understanding of the range of challenges that the industry faces today – be they organisational, technological or commercial. The Ministry of Petroleum and Energy considers it to be important to support and participate actively in these arenas.

INTSOK

In order to promote the internationalisation of Norwegian petroleum-related industry, the authorities established INTSOK – Norwegian Oil and Gas Partners – in 1997, in partnership with the Norwegian petroleum industry. INTSOK is regarded by the Norwegian authorities as an important partner. About 160 companies are members of the foundation. INTSOK aims to promote the Norwegian petroleum industry internationally. Research undertaken by the Institute for Research in Economics and Business Administration indicates that Norwegian supply and services companies had a turnover of 49 billion NOK in overseas markets in 2005, three times the sales in 1995. The goal is for Norwegian petroleum-related companies to increase their annual sales abroad to approximately NOK 80 billion in 2010.

Petrad

As part of its international activities, the Ministry of Petroleum and Energy also supports the Petrad foundation. Petrad is a Norwegian assistance agency, which offers various types of knowledge transfer programs to national oil companies and petroleum authorities in developing countries.

Oil for development

The Ministry of Petroleum and Energy cooperates with the Ministry of Foreign Affairs, the Ministry of Finance and the Ministry of the Environment on a joint program to assist developing countries in petroleum administration and good management. This effort entails financial support through an additional allocation of NOK 50 million per year, starting in 2006. The program includes:

- reinforcing Norwegian bilateral assistance to countries requesting Norwegian petroleum expertise
- emphasis on sound governance and insight in petroleum management

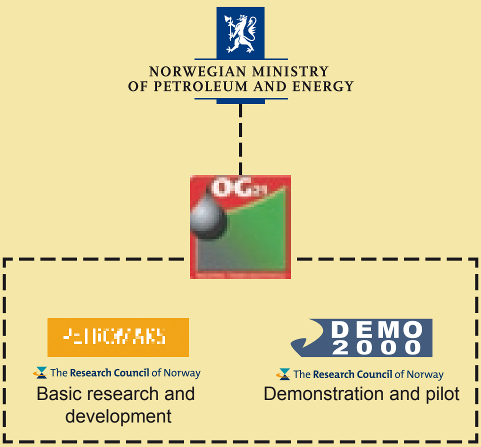


Figure 7.2 Ministry of Petroleum and Energy's involvement in petroleum research
(Source: Ministry of Petroleum and Energy)

Oil for development is a broad-based program, encompassing issues such as resource management, revenue management, the environment and industrial development. Norwegian experts on technical disciplines and petroleum resource management will be involved in the work, including the Norwegian Petroleum Directorate, Petrad and INTSOK. Norad is responsible for coordinating these efforts.

EITI

An important element in the management of the Nowegian petroleum resources is that the tax revenues received by the Norwegian state from the companies active on the Norwegian Contineta1 Shelf should be transparent. Norway supports the international initiative Extractive Industries Transparency Initative (EITI), the aim of which is to promote transparency through the full publication and verification of company payments and government revenues from oil, gas and mining.

States, international companies and non governmental organisations are parties to the process. The process has resulted in a set of standards for the open reporting of income streams and other benefits. Among other things a goal is that it should increase governments' accountability to their citizens with respect to how revenue is spent.

The member companies of the The Norwegian Oil Industry Association share the government's goal of increased transparency in the extractive industries. The association has on behalf of its member companies agreed to make available information on tax payments from oil companies on the Norwegian Continental Shelf to the Norwegian authorities.

Research and technological development in the oil and gas sector

Development of new technology and increased expertise 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. 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 tech-

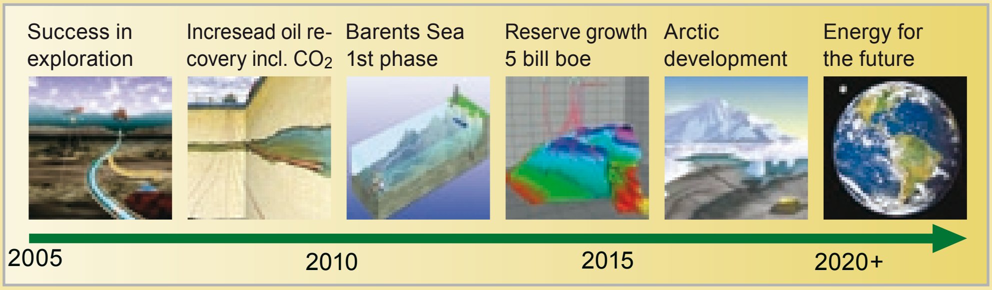


Figure 7.3 OG21's technology road map for value creation on the Norwegian continental shelf

(Source: OG21)

nologically demanding and knowledge-intensive than is the case today. For this reason, continuing efforts in research and technology development are important to ensure that the Norwegian oil and gas industry remains competitive. Figure 7.2 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. The objective was to unite the oil and gas industry in a common national technology strategy (the OG21 strategy). Today, OG21 is organised in a board and a secretariat. The composition of the board is determined by the Ministry of Petroleum and Energy. The link to the petroleum industry is through the OG21 Forum. The vision of OG21 is to develop new technology to maximise value creation on the Norwegian Continental Shelf, as well as increase the export of technology. The OG21 Forum is a meeting place where all parties with interest in petroleum research can participate in the OG21 strategy process.

OG21 has managed to get oil companies, universities, research institutes, the supply industry and the authorities to join forces and support a common national technology strategy for oil and gas. In the International Energy Association's evaluation of Norwegian energy policy in 2005, the OG21 collaboration was recognised as being unique in a global perspective.

The OG21 strategy was revised in 2005 to better adjust to today's challenges. The revised strategy has identified eight core technology areas which will be vital for the future development of the Norwegian petroleum activity:

1 Environmental technology for the future
2 Exploration technology and reservoir characterisation
3 Enhanced recovery
4 Cost effective drilling and intervention
5 Integrated operations and real time reservoir management
6 Subsea processing and transportation
7 Deep water and subsea production technology
8 Gas technologies

OG21's strategy work has laid the foundation for a road map for necessary research and technology development in the Norwegian oil and gas activities. Figure 7.3 depicts this road map.

An important objective for OG21 is to increase state funding of research and development in the petroleum-related area to NOK 600 million per year. OG21 believes that such a public research effort would be commensurate with the main technological challenges in the sector.

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 set in the national technology strategy for the petroleum industry. The funds from the authorities are channelled through the Research Council of Norway, which coordinates the programs.

PETROMAKS

PETROMAKS encompasses both strategic fundamental research and development of expertise, research applications, technological development and research as a basis for formulation of policy. The program's target groups are Norwegian companies and groups that promote the build-up of knowledge and expertise in Norway, as well as productivity, innovation and exports in the petroleum sector.

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. The program has its basis in the national technology strategy.

Furthermore, PETROMAKS finances research-oriented education. The aim is to contribute to an increased level of competence in the petroleum sector as well as to improve recruitment the industry.

Research on arctic-related challenges is financed through the PETROMAKS program. Many of the challenges in the far north are identical to challenges on the whole of the Norwegian continental shelf. The exceptions are, challenges related to extreme climate, less developed infrastructure, development and production in iceinfested areas, handling of ice and transport over very long distances. There are no special Research Programs on the High North organised by the Research Council of Norway. This research is integrated within The Research Council of Norway's activity in entirety, inter alia PETROMAKS.

DEMO 2000

An important initiative in the promotion of new technological solutions within the petroleum industry is the DEMO 2000 program. This program targets projects where new technology can be demonstrated through pilot projects and field tests, and relates particularly to challenges associated with getting research-based innovations out into the market. New technology is often associated with high costs and high risk and DEMO 2000 aims to reduce such costs and risk by supporting pilot projects and demonstrations. The program contributes to the implementation of the national technology strategy.

The pilot projects entail close cooperation with supply companies, 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 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 that their ambition is a realistic one - to ensure that a greater number of new solutions can be put to commercial use in the coming years, both in Norway and abroad, including in technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling and integrated operations (remote control). The value created by innovations within these areas could become enormous.

The DEMO 2000 program emphasises developing and testing petroleum technology which is especially relevant for arctic conditions. Research relevant to the far northern areas is integrated into all the programs of the Research Council of Norway, including DEMO 2000.

PETROSAM

PETROSAM is a new research program which will focus on social-scientific petroleum research. The program was established in 2006 and will last for five years. PETROSAM will contribute knowledge and competence regarding social conditions as an input factor for the strategic and policy-framing work of the government and the petroleum sector. The new program will also focus on international relations, including with the Middle East and Russia.

PROOF

Budget funds from the Ministry of Petroleum and Energy are also allocated to important R&D activities relating to the environment. The research program PROOF examines the long-term effects of discharges to sea from the petroleum activities, and constitutes a part of the larger program, "The Sea and the Coast", planned for the period 2006–2015.

Other strategic research

The fundamental research within the framework of priorities for petroleum-related subjects aims to establish R&D expertise of high international quality in the university and institute sector. For research institutions, the strategic institute program (SIP) is part of the basic allocation, as defined by the Ministry of Education and Research.

CLIMIT

CLIMIT is a cooperative program between Gassnova and the Research Council of Norway, and relates to research, development and demonstration of technology associated with environmentally friendly gas-fired power production. Gassnova is financed by the Gas Technology Fund's returns. Climit's vision is to contribute to profitable CO_2 capture from gas-fired power plants. The program will cover the entire chain from long-term research to upgrading skills to provide support for projects demonstrating CO_2 capture technologies. The project portfolio will mainly focus on technology solutions for cost-effective CO_2 capture. In addition, development of knowledge and solutions for safe and reliable capture of CO_2 in geological formations is a priority.

The CLIMIT program encompasses all phases of development and commercialisation of new solutions. The CLIMIT-program administers approximately 150 MNOK for support activities in 2007.

8 Government petroleum revenues

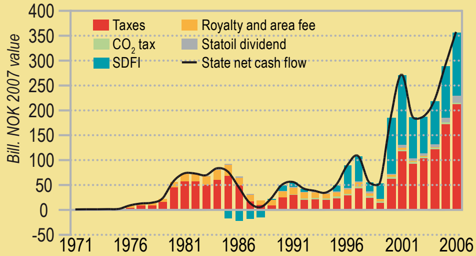


Figure 8.1 The net government cash flow from petroleum activities *(Source: State accounts, 2006 from the National Budget for 2007 and preliminary accounting figures)*

Direct taxes:	211.9
Royalty, CO_2-tax:	4.0
SDFI:	126.7 *
Statoil dividend:	14.0 **
Total:	**356.5**

* SDFI annual accounts 2006 (exept insurances (SPFF))
** Based on dividend for 2006 proposed by Statoil's board of directors

Figure 8.2 The net government cash flow from petroleum activities 2006 (bn. NOK) *(Source: National Budget)*

The government earns high revenues from the petroleum sector. In 2006, 36 percent of government revenues stemmed from this sector. Figure 8.1 shows income from the sector, which has been high in recent years, and 2006 was a year with very high payments to the state. The value of the remaining petroleum reserves on the Norwegian continental shelf was estimated at NOK 4160 billion in the National Budget for 2007.

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

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

Why does Norway have a special system for government take when it comes to petroleum revenues? The main rationale for the system is the extraordinary returns associated with production of the resources. The fiscal system must be understood in connection with the common ownership of the resources on the Norwegian continental shelf, and that the oil companies are allowed to exploit a valuable, limited resource.

The petroleum tax system

Petroleum taxation is based on the Norwegian rules for ordinary corporation tax. Due to the extraordinary profitability associated with production of the Norwegian petroleum resources, a special tax is also levied on income from these activities. The ordinary tax rate is the same as for land activities, 28 percent, while the special tax rate is 50 percent. When calculating taxable income for both ordinary and special taxes, an investment is subject to depreciation on a linear basis over six years from the date it was made. Companies may deduct all relevant expenses, including exploration, research and development, net financial, operating and decommissioning expenses (see figure 8.3). Consolidation between fields is permitted. In order to shield the normal return from the special tax, an extra deduction, the uplift, is allowed in the calculation base for special tax. This amounts to 30 percent of the investments (7.5 percent per annum for four years from the year the 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 for neutrality, so that an investment project that is profitable for an investor before tax, will also be profitable after tax. It is, therefore, possible to harmonise the requirement for significant revenues to the society with the requirement for sufficient post-tax profitability for the companies.

Other taxes

The most important other taxes linked to petroleum activities are the carbon dioxide tax, the NOx 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. The rate for 2007 is NOK 0.80 per litre of petroleum or scm of gas.

Pursuant to the Gothenburg Protocol of 1999, Norway has an obligation to reduce annual emissions of nitrogen oxides (NOx). In order to fulfil this obligation, a tax of NOK 15 per kg of NOx has been introduced as from 1 January 2007.

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

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.

Norm prices

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

It can often be a very difficult task for the petroleum tax authorities to assess whether prices agreed between two parties is equal 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 regulations.

The norm price is fixed by the Norm Price Board, and should be equivalent to the price paid for the petroleum had it been traded between independent parties. The norm price is stipulated each month and for each field. The Norm Price Board 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 Norm Price Board does not find it appropriate to stipulate a norm price, the actual 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.

The State's Direct Financial Interest (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. Each government take is decided when production licences 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 privatised and listed on 18 June 2001, the administration of the SDFI portfolio was transferred to the state-created trust company, Petoro.

The SDFI arrangement implies that the state, when awarding acreage, can determine exactly how much of the value creation shall devolve on the state. For production licences for which profitability is expected to be low, the state can decide to take a small, or even no, interest, while a larger share would be appropriate for more profitable areas.

Statoil dividend

As of 1 March 2007, the state owns 70.9 percent of the shares in Statoil. As an owner in Statoil, the state receives dividends, which form part of the state's revenues from the petroleum sector.

9 Environmental considerations in the Norwegian petroleum sector

Norway as a pioneer in environmental solutions

Consideration for the environment is integrated in the Norwegian petroleum activities. In order to ensure that Norway can combine its role as a major energy producer with being a pioneer in environmental issues, 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. As a result of this strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental standards. This chapter provides an overview of policy instruments designed to ensure that the environment is taken into consideration, measures implemented to reduce emissions and discharges, as well as the status of emissions to air and discharges to sea from the petroleum activities.

The various phases of the petroleum activities give rise to different types of emissions and discharges. Exploration activity entails discharge of drill cuttings and emissions to air from energy production. Exploration activity also entails the danger of acute oil spills which can harm larvae, fish eggs, fish, seabirds, marine mammals and organisms in the beach zone. Fortunately, acute spills are very rare. During the operations phase there are discharges to sea and emissions to air, primarily water with residues of oil and chemicals (produced water), carbon dioxide (CO_2) and nitrogen oxides (NOx) from energy production and flaring and non-methane volatile organic compounds (nmVOC) from storage and loading of crude oil. There is also some danger of oil spills during the operations phase.

Policy instruments

Emissions and discharges from petroleum activities in Norway are regulated by the Petroleum Act, the CO_2 Tax 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 base lines are also subject to scope and extent of the Planning and Building Act (see Chapter 4).

The authorities employ various policy instruments in the different phases of petroleum activity, from the exploration phase through the operations phase and finally, decommissioning. The policy instruments also vary according to the different types of emissions to air and discharges to sea.

International agreements and obligations

In accordance with international agreements, Norway is obliged to limit its emissions of various components. How this affects the petroleum sector will depend on how the individual agreements are worded, and how the requirements and policy instruments are distributed by sector in Norway. Air pollution agreements normally specify an emissions threshold for each country. The wording of the agreements determines whether the imposed limits must be implemented in their entirety within each country's borders, or whether reductions can also be made in other countries where the costs of such reductions may be lower. The costs of reducing emissions from the various sources, both domestic and international, will help determine the degree to which measures will be implemented in the petroleum sector.

Global climate pollution is regulated by the UN Climate Convention. According to the Kyoto Protocol, Norway is obliged to ensure that average emissions for the years 2008–2012 do not increase

Policy instruments to reduce emissions/discharges from the petroleum activities

CO_2

The CO_2 Tax Act and the Greenhouse Gas Emission Trading Act constitute the key policy instruments designed to reduce emissions of CO_2. The authorities can also apply other policy instruments, such as terms and conditions in PDOs/PIOs, emission/discharge permits and production permits, which also cover flaring.

With effect from 1 January 1991, the use of gas, oil and diesel in association with petroleum operations on the Norwegian continental shelf is subject to CO_2 tax under the CO_2 Tax Act. As of 1 January 2007, the CO_2 tax is NOK 0.80 per litre of oil and standard cubic metre (scm) of burned gas (or approximately NOK 330/tonne CO_2). Under the Petroleum Act, burning of gas through flaring, beyond what is necessary to ensure the safety of normal operations, is not permitted without consent from the Ministry of Petroleum and Energy. The Greenhouse Gas Emission Trading Act established a system of quota obligations and marketable quotas for the period 2005–2007. In the petroleum sector, only a few facilities on land, such as gas processing plants and gas terminals, are subject to quota obligations. The Greenhouse Gas Emission Trading Act will be reviewed by the end of 2007. The Government has indicated the possibility of including the Greenhouse Gas Emission Trading Act in the EEA Agreement. If the Greenhouse Gas Emission Trading Act is included in the EEA Agreement, the petroleum sector will be included in the Norwegian emissions trading system from 2008 onwards, together with the facilities already subject to quota obligations.

NOx

The Parliament decided on the 28th of November 2006 to introduce a NOx tax. The tax was implemented pursuant to the Act concerning sales tax. The tax covers the total emissions from the petroleum sector from turbines with effect over 10 MW and engines over 750 hp. In addition, the tax covers emissions from flaring. The tax is set to 15 NOK per kilo NOx. How to estimate the NOx emissions is given account for in the duty. The purpose of the tax is to reduce the annual NOx emissions to 156 000 tonnes by 2010, in accordance with Norway's commitment under the Gothenburg Protocol from 1999 (ratified by Norway 30th of January 2002). The tax primarily targets emissions from onshore industry and covers emissions from big units in shipping, air transport, onshore industry and the continental shelf. Liable to the tax are shipping companies or ship owners, owner of onshore industry and operators on the continental shelf.

nmVOC

Discharges of nmVOC associated with loading and storage of crude oil offshore have been regulated since 2001 by means of discharge permits issued pursuant to the Pollution Control Act.

Oil, organic compounds and chemicals

Companies must apply for discharge permits from the Norwegian Pollution Control Authority in order to discharge oil and chemicals to sea. The Norwegian Pollution Control Authority grants discharge permits pursuant to the provisions of the Pollution Act. Under the Pollution Act, the operating companies themselves are responsible for and obliged to establish the necessary contingency planning measures to counteract acute pollution. Municipal and national emergency response plans are also in place.

by more than one percent compared to the emissions level in 1990. Relative to current levels, this implies a reduction of approximately eight percent. The obligation can be met through reducing domestic emissions here in Norway, and in other countries by the use of the Kyoto mechanisms (international emission trading, the green development mechanism and joint implementation). With the Greenhouse Emission Trading Act, Norway has established a national quota system for greenhouse gases from 2005, as a follow-up to the Kyoto Protocol.

Emissions with regional environmental impact are regulated by various protocols under the Convention on Long-Range Transboundary Air Pollution (LRTAP). In 1999, together with the USA, Canada and other European countries, Norway signed the Gothenburg Protocol, which aims to solve the environmental problems of acidification, eutrophication and ground-level ozone. The Gothenburg Protocol entered into force on 17 May 2005. Under this protocol, Norway is to reduce NOx emissions to 156,000 tonnes by 2010. This implies a 27 percent reduction for Norway, compared to 1990 emission levels. The new commitment for nmVOC is virtually unchanged from the one accepted by Norway under the existing Geneva Protocol, i.e. that annual nmVOC emissions from all of the mainland and the Norwegian economic zone south of the 62nd parallel should be reduced as quickly as possible by 30 percent from the 1989 level. Under the Gothenburg Protocol, total national emissions shall not exceed 195,000 tonnes per year by 2010.

Discharges of oil and chemicals may have local impacts in the immediate vicinity of the facilities. These discharges are regulated on a national basis through a permit system pursuant to the Pollution Act. These discharges are also regulated internationally through the OSPAR Convention. For discharges to sea, an international maximum level for oil content in water has been reduced to 30 mg per litre from 1 January 2007. Use and discharge of chemicals is subject to international regulation in the form of mandatory risk assessment and classification according to the properties of the chemicals.

Zero environmentally hazardous discharges to sea

The objective of zero environmentally hazardous discharges to sea from the petroleum activities was established in White Paper No 58 (1996–1997) Environmental Policy for Sustainable Development to the Storting. Since then, the authorities and the industry have worked together in a dedicated group to precisely define the objective and identify methods for achieving this goal. This objective has also been discussed in several subsequent White Papers.

The zero discharges targets constitute a goal based on a precautionary principle to help ensure that discharges to sea of oil and environmentally hazardous substances do not lead to unacceptable risks to health or the environment. No discharge of environmentally hazardous substances is the main rule; neither chemical additives nor naturally occurring chemical substances.

When selecting measures to reduce discharges from the individual fields, an overall assessment of the consequences for the environment, costs, safety and reservoir aspects must be carried out in the early work towards developing fields. This was appointed in the early work. It is therefore possible that the achievable target in practical terms on an existing field, based on such field-specific overall assessments, is minimising discharges. Operating companies on the Norwegian continental shelf was expected to be ambitious in their endeavours to achieve this goal, and they were also expected to work actively to develop and put to use new techniques that can contribute to achieving this goal.

Definitions of zero discharges and zero discharges targets

Definitions

Environmentally hazardous, 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, 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

Environmentally hazardous substances:

- Zero discharges, or minimisation of discharges of naturally occurring environmental toxins encompassed by end objective No. 1 for chemicals hazardous to health and the environment, ref. the priorities list in White Paper No. 25 (2002–2003) to the Storting.
- 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 of the following substances that can lead to harm to the environment:

- oil (components that are not hazardous to the environment)
- substances in the Norwegian Pollution Control Authority's yellow and green categories
- cuttings
- other substances that can lead to harm to the environment

White Paper No. 38 (2003–2004) On the petroleum activities to the Storting, 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.

**Ref. Regulations relating to conduct of activities in the petroleum activities (the Activities Regulations) of 3 September 2001.*
Source: White Paper No. 25 (2002–2003) The Environmental Policy of the Government and the State of the Environment in Norway to the Storting.

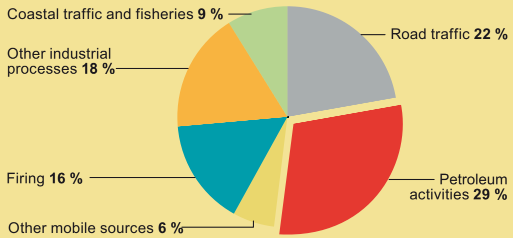


Figure 9.1 Sources of Norwegian emissions of CO_2, 2005
(Source: Statistics Norway)

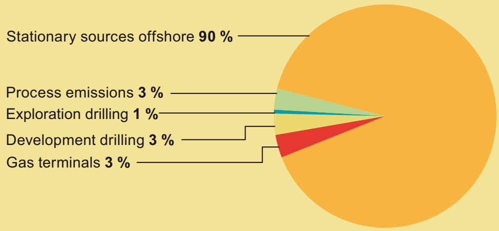


Figure 9.2 CO_2 emissions from petroleum activities 2005, by source
(Source: Norwegian Petroleum Directorate)

The oil industry has invested approximately NOK 6 billion in efforts to reduce discharges to sea since 2002.

As a step in their work to achieve zero environmentally hazardous discharges to sea, the operating companies have reported to the authorities concerning relevant measures, with associated costs and impact on the environment, as well as the current status. Replacement of environmentally hazardous chemicals is, in general, a cost-effective measure. Discharges of environmentally hazardous chemical additives have been reduced as much as possible in accordance with prudent technical and safety factors. The zero discharge target is therefore considered to be achieved as regards these substances.

With regard to oil and naturally occurring substances in produced water, process optimisations, reinjection of produced water and cleaning measures appear to contribute most to reducing the risk of harm to the environment, within an acceptable cost frame.

Reports from the companies show that many measures have been implemented, and there has been a substantial improvement in the environment. Initially, the goal of zero environmentally hazardous discharges to sea should have been met in 2005. On several fields, however, the process of evaluating, testing and implementing measures has been more time-consuming than expected. This is due to greater technological challenges than presumed, and the need for further adjustments and testing of equipment. Thus, full effect from the measures can not be expected until in 2007/2008.

Emissions and discharges from the petroleum activities

Emissions to air from the petroleum sector largely consist of exhaust gases from combustion of gas in turbines, flaring and combustion of diesel. These exhaust gases contain substances such as CO_2 and NOx. Other environmentally hazardous substances released to air include nmVOC, methane (CH_4) and sulphur dioxide (SO_2). Discharges to sea from the petroleum sector contain residues of oil and chemicals used in the production processes, as well as naturally occurring chemical substances.

Measuring and reporting discharges and emissions

In most cases, emissions to air are calculated on the basis of the volume of fuel gas and diesel consumed on the facility. The emissions factors are based on measurements from suppliers or standard figures developed by the industry itself, through the Norwegian Oil Industry Association. On most fields, emissions are calculated using field-specific factors. Software that can calculate emissions based on measured process parameters is also available.

When calculating total oil discharges, the volume of produced water discharged to sea is measured, followed by an analysis of the oil content in the water. Discharge of chemicals is calculated based on consumption, relative to how much is recovered and/or injected.

The Norwegian Pollution Control Authority, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database 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.

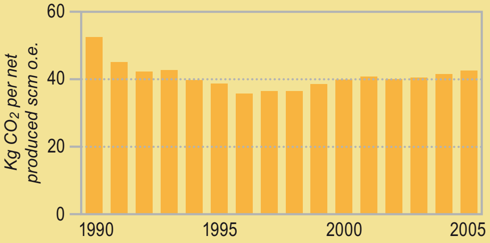


Figure 9.3 Emissions of taxable CO_2 per produced unit

(Source: Norwegian Petroleum Directorate)

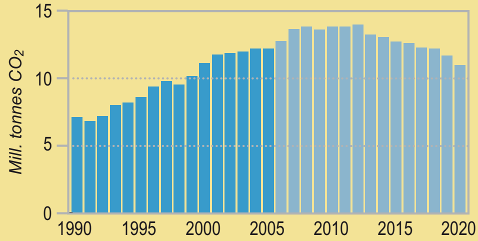


Figure 9.4 Emissions of CO_2 from the Norwegian petroleum sector

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

Emission status for CO_2

CO_2 emissions associated with the facilities on the Norwegian continental shelf largely originate from combustion of gas in turbines, flaring of gas and combustion of diesel. CO_2 is the most important of the greenhouse gases, and is largely derived from combustion of fossil fuels. Of all the fossil fuels, natural gas gives the lowest CO_2 emissions per energy unit.

The environmental effects of CO_2 emissions include the following:

- CO_2 contributes to the greenhouse effect, which in turn causes global warming.
- High concentrations of CO_2 in the atmosphere may result in more CO_2 dissolved in water, which can in turn lead to a reduction of the pH value in the sea.

In a national context, petroleum activities are responsible for 29 percent of CO_2 emissions (see figure 9.1). This percentage is expected to fall in the years to come. Other major emission sources in Norway include road traffic and other mobile sources, heating and emissions from industrial processes.

As shown in figure 9.2, the majority of the CO_2 emissions from the petroleum sector are linked to the offshore facilities. Other CO_2 emissions come from gas terminals on land and indirectly from VOC emissions (so-called process emissions).

Improved energy efficiency and reduced flaring have led to a reduction in CO_2 emissions per produced oil equivalent of approximately 19 percent from 1990 to 2005 (see figure 9.3). This is a result of a general improvement in technology and measures that reduce the emissions, such as the CO_2 tax introduced in 1991. However, the reduction in CO_2 emissions per produced oil equivalent has not been large enough to offset the increase in energy consumption resulting from a higher level of activity on the Norwegian continental shelf (see figure 9.4). In particular, increased gas production with subsequent gas compression for export has led to greater energy consumption, which in turn increases emissions of CO_2.

Generally speaking, emissions associated with production of a unit of oil or gas will vary between fields, as well as over the lifetime of a specific field. Reservoir conditions and transport distance to the gas market are factors that cause energy requirements, and thus emissions, to vary from field to field. The fact that emissions also vary over the lifetime of a specific field is in part due to an increasing amount of water in the wellstream as the field ages. As the energy required in the process facility largely depends on the total volume of liquid and gas (water, oil and gas), a field will have higher emissions per produced unit as it matures. This is one of the reasons for the slight increase in emissions per unit in recent years. The trend on the Norwegian continental shelf towards more mature fields and movement of activity northward reinforces the development of more emissions per produced unit. Treatment and transport of produced gas requires more energy than liquid production. Production of gas accounts for an increasing percentage of production on the Norwegian continental shelf. This has a significant impact on the development of the indicator CO_2 emissions per produced unit.

Measures for reducing CO_2 emissions

Development of combined solutions for energy production offshore (combined cycle power plants), recirculation of flare gas and injection of CO_2 from produced gas at Sleipner Vest are examples of the Norwegian continental shelf 's leading-edge position in terms of implementing efficient environmental solutions.

Combined power solutions
Combined cycle power plants are a solution whereby heat from turbine exhaust gas is used to produce steam, which in turn is used to generate electric power. Combined cycle power increases energy efficiency, and 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 water or on land. Since 1996, 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. When the Snøhvit field commences production in 2007, CO_2 from the gas production will be separated out before the natural gas is cooled to liquid natural gas (LNG). The CO_2 gas will be transported via pipeline from the LNG plant on Melkøya and back to the field for reinjection into the Tubåen formation. Approximately 700,000 tonnes of CO_2 will be stored in Tubåen each year.

In the future, Norway will have excellent opportunities for storing CO_2 due to its access to large, water-filled reservoirs and depleted oil or gas reservoirs off the Norwegian coast. Storing CO_2 in depleted reservoirs is a good solution in terms of geology, because the structure is likely to be impermeable inasmuch as it has contained oil and gas for millions of years.

The Norwegian authorities work actively to ensure that such storage of CO_2 can be achieved in a safe and secure manner. Work is therefore being undertaken under the auspices of the OSPAR and London Conventions to ensure that sound international regulations for CO_2 storage are established. In the autumn of 2006, it was agreed under the London Convention to allow injection and storage of CO_2 in geological formations under the seabed. This change entered into force on 10 February 2007. Work is being undertaken to ensure that the OSPAR Convention follows the London Convention on this.

The Ministry of Petroleum and Energy has given Gassco, Gassnova, the Norwegian Petroleum Directorate and the Norwegian Water Resources and Energy Directorate the task of evaluating different solutions for transport and storage. The group is to make a recommendation on solutions for transport and storage of CO_2 from Kårstø and Mongstad. As regards cost evaluations, consideration shall be given to aspects related to reservoirs and technological risk. We assume that Kårstø and Mongstad will be reviewed together. Initial recommendations will be submitted in June 2007.

Use of CO_2 to enhance oil recovery
The Norwegian Petroleum Directorate has estimated that there is a significant technical potential for improved oil recovery through the use of CO_2 in oil fields on the Norwegian continental shelf. The government has ambitious goals for realising CO_2 handling and creating a value chain for transport and injection of CO_2. These are demanding goals with tight deadlines. The government has initiated projects to ensure progress in the work to establish a CO_2 chain and enlist relevant players in the work. Gassco was to coordinate the first project with the purpose of examining to what extent CO_2 chains are feasible on commercial grounds. In the report

from June 2006, 12 CO_2 chains are identified but none show a positive present value.

Power plants and energy efficiency

CO_2 emissions from power production account for approximately 80 percent of the total emissions from offshore activities. In 2004, the authorities and the industry worked together to carry out a study of the potential for more efficient power supply on the Norwegian continental shelf. The study concluded that a realistic, although ambitious, estimate of potential emission reductions was between five and ten percent over a period of ten years. The industry followed up the report from the authorities and in spring 2006 the Norwegian Oil Industry Association published a guidance which helps the companies to systemise and formalise the work considering energy management and which builds on the same principles as approved standards for environmental management, e.g ISO 14001 and EMAS.

A change in technology and energy supply concepts will be needed to ensure further increases in energy efficiency over the longer term. This calls for a long-term commitment to developing, testing and implementing new technology.

Flaring

Although flaring accounts for approximately ten percent of the CO_2 emissions from the petroleum activities, levels in Norway are low compared with other countries (see figure 9.5). The CO_2 tax and direct regulation of flaring have triggered a number of emission-reduction measures, and Norway leads the field in this area.

Emission status for NOx

Emissions of CO_2 and NOx 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 NOx. The volume of emissions depends both on the combustion technology and the quantity of fuel used.

The environmental effects of NOx emissions include the following:

- impact on fish and other fauna through acidification of watercourses and the ground
- damage to buildings, stone and metalwork resulting from acid rain
- eutrophication, which may lead to a change in the composition of species in ecosystems
- damage to health, crops and buildings due to production of ground-level ozone

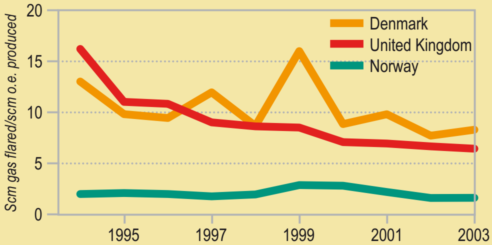


Figure 9.5 Flared gas per produced unit in Denmark, UK and Norway, 1994-2003

(Source: Norwegian Petroleum Directorate)

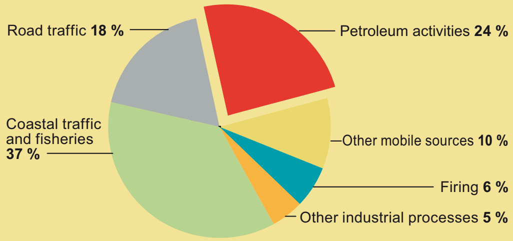


Figure 9.6 Sources of NOx emissions in Norway, 2005
(Source: Statistics Norway)

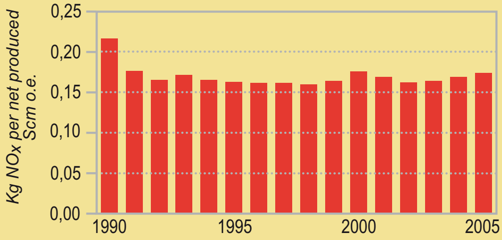


Figure 9.7 NOx emissions per produced unit
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

Mobile sources account for the majority of the Norwegian NOx emissions (see figure 9.6). The petroleum sector contributes with 24 percent. Emissions of NOx per produced oil equivalent have declined by 18 percent from 1990 to 2004 (see figure 9.7). The reductions in emissions per produced oil equivalent are the result of improved technology and measures to reduce emissions. Despite the reduction in emissions per produced oil equivalent, total emissions of NOx from the sector have increased compared with 1991 (see figure 9.8). The main cause of the growth so far is increased activity which has entailed a need for more energy, which in turn means more emissions. Emissions of NOx are expected to fall from 2009.

Measures for reducing NOx emissions

Most of the measures designed to reduce CO_2 emissions also contribute to reducing NOx emissions from the petroleum sector. Other measures that can help reduce NOx emissions include introducing low-NOx burners as standard on gas turbines on new facilities. NOx emissions can be reduced by as much as 90 percent with no change in CO_2 emissions. In some cases, however, use of this technology can lead to increased CO_2 emissions.

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

Injection of steam or water in the combustion chamber can reduce NOx emissions. Steam or water will be used to reduce the combustion temperature and thus NOx emissions. This technology requires large quantities of clean water, which is a challenge offshore. This technology will however contribute to NOx emissions reduction in the in the petroleum sector.

Emission status for nmVOC

nmVOC stands for non-methane volatile organic compounds, which vaporise from substances such as crude oil. In the petroleum sector, most of these emissions derive from offshore and onshore storage and loading of crude oil.

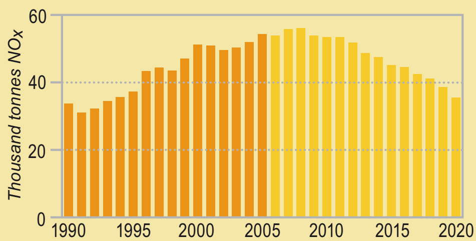


Figure 9.8 Emissions of NOx from the petroleum sector
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

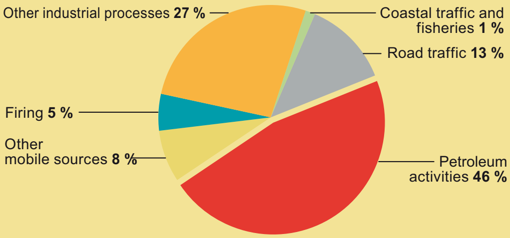


Figure 9.9 Sources of Norwegian emissions of nmVOC, 2005
(Source: Statistics Norway)

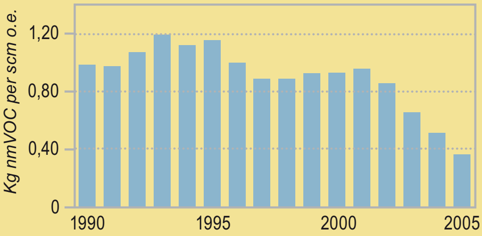


Figure 9.10 Sources of nmVOC emissions per produced unit
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

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
- 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 is the main source of nmVOC emissions in Norway (see figure 9.9), accounting for approximately 46 percent of total emissions. Emissions of nmVOC largely originate from storage and loading of crude oil offshore. Minor emissions also occur at the gas terminals and in connection with small leaks. 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 in recent years (see figure 9.10).

There are large differences in emissions depending on where the oil is loaded. The main reason for this is that the content of volatile gases in the oil varies from field to field.

Several of the newer fields on the Norwegian continental shelf use floating storage facilities. This type of development can result in higher emissions of nmVOC than on fields where oil storage takes place in the base of the platforms (Statfjord, Draugen and Gullfaks). This is because the use of floating storage facilities also entails emissions between production and storage.

The forecast for emissions of nmVOC from the sector shows a distinct declining trend in the years to come (see figure 9.11). Implementation of emission-reducing technology is the reason for this. Moreover, oil production is expected to reach its peak a few years from now.

Measures 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 percent. Several vessels have now installed tech-

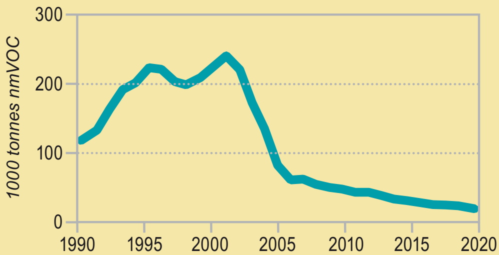


Figure 9.11 Emissions of nmVOC from petroleum activities
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

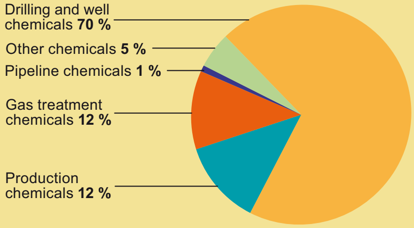


Figure 9.12 Discharges of chemicals from petroleum activities, by sources, 2005
(Source: EnvironmentWeb)

nology to reduce emissions. The operators of fields with buoy loading on the Norwegian continental shelf have formed a joint venture (see text box).

A recovery facility for nmVOC was deployed at the crude oil terminal at Stura 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.

Discharge status for chemicals, oil and other organic compounds

Discharges of 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 as well as natural chemicals. The main rule is that no environmentally hazardous substances may be discharged, regardless of whether the substance is an additive or occurs naturally.

More than 99 percent 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, ref. the Norwegian Pollution Control Authority's classification). 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:

- 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.

Industry joint venture

Emission permits entail a requirement whereby oil must be stored and loaded using the best available emission-reducing technology (BAT). Technologies designed to meet this requirement will be implemented according to a specified timetable extending to the end of 2008.

Operators of Norwegian continental shelf fields with buoy loading have established a joint venture to coordinate phase-in of technology and to fulfil the requirement in an expedient and cost-effective manner. The joint venture paves the way for exchange of experience with regard to operation of the facility.

The joint venture agreement was signed in 2002, and 26 companies take part in this collaboration which covers buoy loading of oil from Varg, Glitne, Jotun, Balder, Gullfaks, Statfjord, Draugen, Njord, Åsgard and Norne.

At the end of 2005, nmVOC-reducing technology had been installed on 13 buoy loaders, as well as on two ships transporting oil from Heidrun. The nmVOC-emissions was reduced by approximately 40,000 tonnes. Focus in the future will be on measures to achieve high operational regularity on existing facilities.

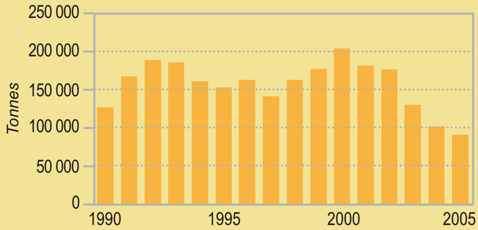


Figure 9.13 Total discharges of chemicals from petroleum activities
(Source: EnvironmentWeb)

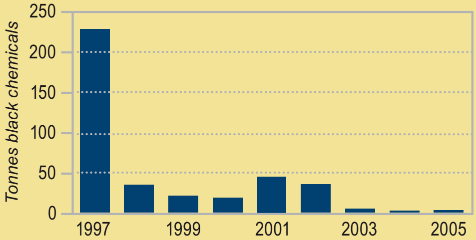


Figure 9.14 Discharges of black chemicals from petroleum activities
(Source: NOIA/EnvironmentWeb)

- A small percentage of chemical discharges may have very serious environmental consequences, including hormone disruption or bioaccumulation.

Potential long-term effects remain uncertain, but considerable research is being done in this area.

Most chemical discharges are associated with drilling activity (see figure 9.12), and discharge volumes vary according to the level of activity taking place. Figure 9.13 shows the development in total discharges of chemicals from the petroleum activities. Discharges of added environmentally hazardous production chemicals (black and red chemicals, ref. Norwegian Pollution Control Authority's classification) have been reduced by almost 92 percent from 2000 to 2005. Figures 9.14 and 9.15 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.

Discharges of oil and other naturally occurring chemical substances

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 is considered to come from shipping and from the mainland via rivers. Figure 9.16 provides an overview of acute oil discharges greater than one tonne. 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.

Petroleum activities have not caused major acute spills of oil that have reached land. 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 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.

Oil discharges from the petroleum sector largely occur in connection with ordinary operations. Water that is produced with oil and gas contains

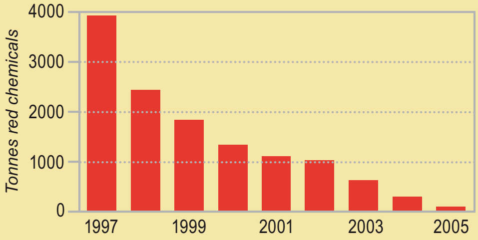


Figure 9.15 Discharges of red chemicals from petroleum activities
(Source: NOIA/EnvironmentWeb)

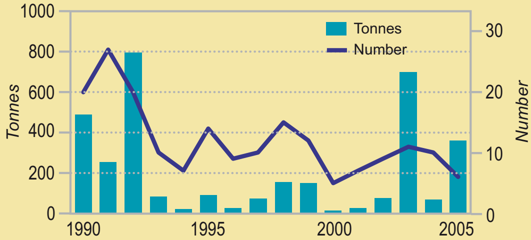


Figure 9.16 Acute oil discharges of more than one tonne
(Source: EnvironmentWeb)

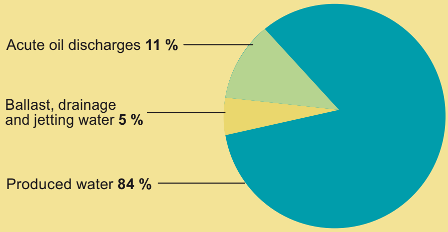


Figure 9.17 Discharges of oil from petroleum activities, by activity, 2005
(Source: EnvironmentWeb)

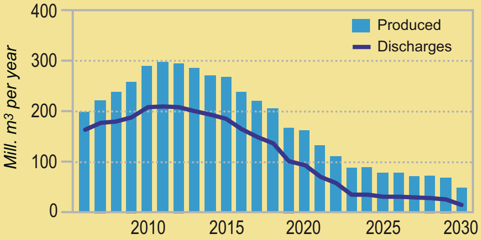


Figure 9.18 Forecast for produced water and dischage of produced water
(Source: Ministry of Petroleum and Energy/Norwegian Petroleum Directorate)

remnants of oil in the form of droplets (dispersed oil), other organic components (including dissolved oil fractions), inorganic components (heavy metals, naturally low-radioactive compounds, etc.) and residues of chemical additives. The produced water is reinjected into the subsurface or cleaned to the extent possible before it is discharged to sea. Figure 9.17 shows oil discharges distributed between activities, while figure 9.18 illustrates the development in the volume of produced water and discharges of produced water, both historical and forecast. Implemented actions have led to considerable reductions in the discharge of oil per unit of produced water. Due to maturing fields, the implemented actions do not exceed the increase in the discharge. These actions have although stabilized the discharge at the current level. Figure 9.19 shows the total oil discharge and the average concentration of dispersed oil in water (mg/litre).

There is no proof of direct harm to the environment from operational discharges of oil. New research results indicate that alkyl phenol in produced water does not entail a risk to the fish populations in the North Sea. However, potential long-term effects are uncertain and substantial research is being done on this topic, including through the research program “Sea and Coast”, and its subsidiary program, PROOFNy.

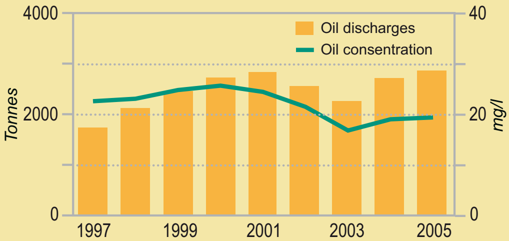
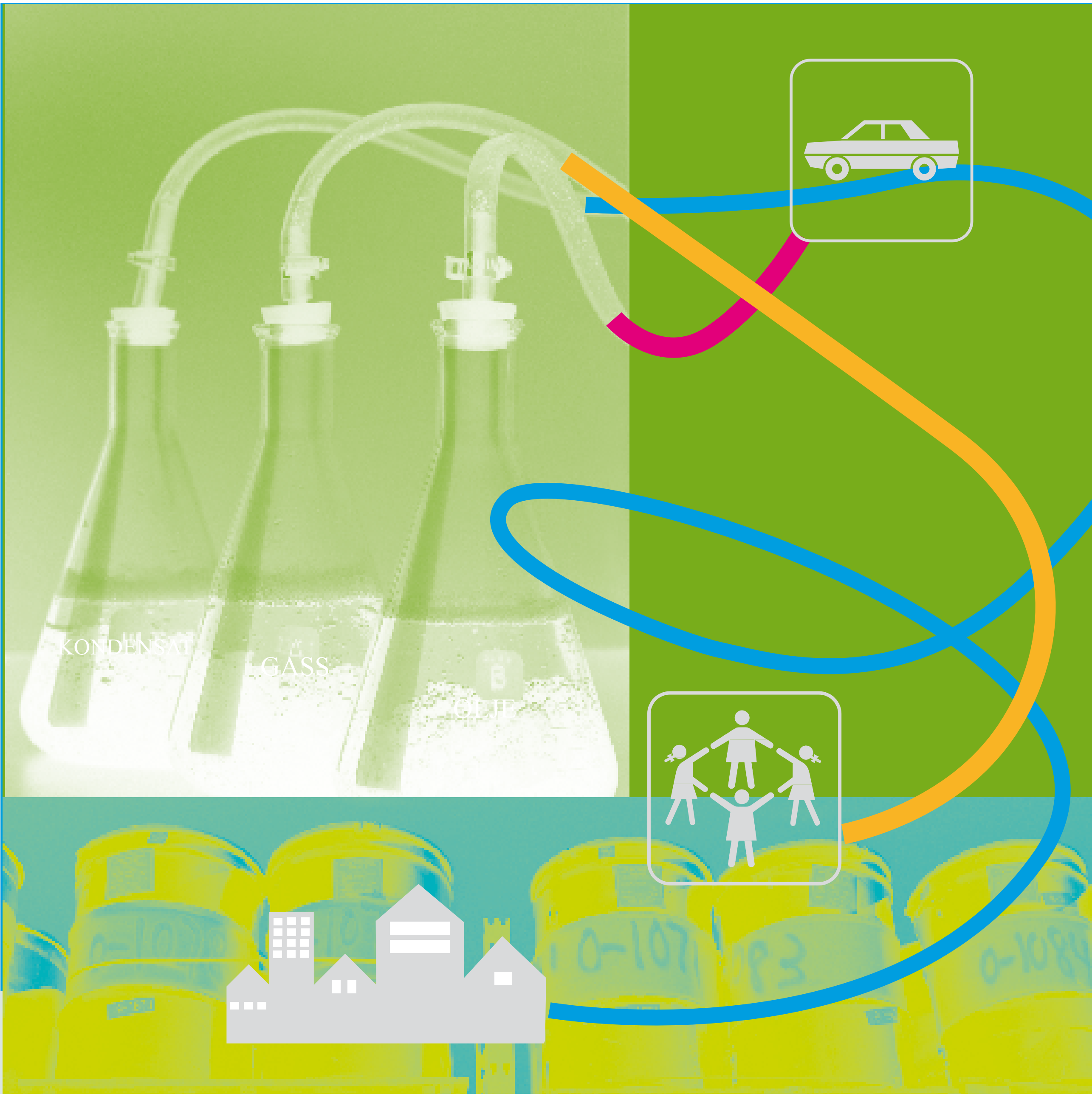


Figure 9.19 Total oil discharge and the average concentration of dispersed oil in water (mg/litre)
(Source: EnvironmentWeb/ Norwegian Pollution Control Authority)

10 Petroleum resources



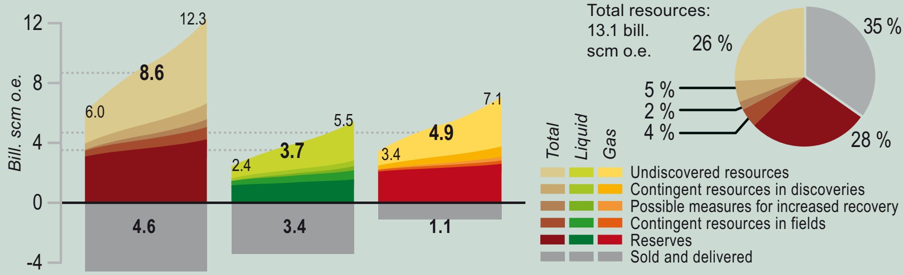


Figure 10.1 Petroleum resources and uncertainty in the estimates at 31.12.2006
(Source: Norwegian Petroleum Directorate)

The Norwegian Petroleum Directorate (NPD) estimates that the total discovered and undiscovered petroleum resources on the Norwegian continental shelf (NCS) amount to approximately 13 billion standard cubic meters of oil equivalents (scm o.e.). Of this amount, a total of 4.6 billion scm o.e., or 35 per cent of the total resources, have been produced. The total remaining recoverable resources amount to 8.6 billion scm o.e. Of this amount, 5.2 billion scm o.e. are proven resources, while undiscovered resources are estimated to account for 3.4 billion scm o.e.

Resource growth from exploration activity in 2006 was low. Six new discoveries were made in four wellbores. The total recoverable resources from exploration activity are 21 million scm oil and 9 billion scm gas. Some of the discoveries are still being evaluated and the estimates are thus very uncertain.

Since petroleum production began on the Norwegian continental shelf in 1971, a total of 4.6 billion scm o.e. have been produced from 65 fields. In 2006, the Gimle and Ringhorne Øst fields commenced production. Of the fields on stream at the end of 2006, 44 were in the North Sea and eight were in the Norwegian Sea. A PDO for a new field, Tyrihans, was approved in 2006. Amended PDOs were also approved for Kvitebjørn and Tordis. PDO exemptions were granted for Gimle and deposits in the Sleipner area.

Figure 10.1 shows the total recoverable potential on the NCS. The volumes are divided according to the Norwegian Petroleum Directorate's resource classification, and show total resources, liquid and gas.

Resources

Resources is a collective term that covers technically recoverable quantities of petroleum. The resources are classified according to maturity, see figure 10.2. The classification shows the size of the petroleum volumes that the licensees have decided to develop, or are approved for development (reserves), the volumes that depend on clarification and decisions (contingent resources) and the size of the volumes that we expect will be discovered (undiscovered resources). The main classifications are reserves, contingent resources and undiscovered resources.

The detailed resource accounts as of 31 December 2006 are shown in Table 10.1 and in tables in Appendix 2.

Reserves

Reserves include remaining recoverable petroleum resources in deposits that the licensees have decided to develop, and 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 plan has not been processed by the authorities in the form of a PDO approval or a PDO exemption. The reserves are estimated at 3.7 billion scm o.e. In 2006, the gross reserves increased by just 10 million scm o.e. In spite of an increase in reserves on several fields as well as maturation from resources to reserves, there were reductions in reserves in existing fields in total. Gross gas and liquid reserves increased by 10 million scm o.e. Since 249 million scm o.e. were produced, the resource accounts show a net reduction in remaining reserves of 239 million scm o.e.

In relation to the authorities' new goal of maturing 800 million scm of oil as reserves prior to 2015, 154 million scm of oil were entered as reserves in 2005. The 2006 accounts lead to a reduction in the achieved resource growth of 18 million scm oil.

Contingent resources

Contingent resources refers to discovered quantities of petroleum for which no development decision has yet been made. Contingent resources in fields, not including resources from potential measures to improve recovery, were increased by 82 million scm o.e. in 2006. The reason for this increase is a substantial maturing of projects in fields in 2006, as well as the initiation of new projects in fields. On fields including Balder, Heidrun, Troll, Åsgard, Mikkel and Valhall, the licensees have initiated new projects to improve long-term recovery.

The estimate for contingent resources in discoveries has been adjusted downward by 73 million scm o.e. to 654 million scm o.e. The reduction is a result of minor additions from exploration, as well as maturing of resources to reserves for the 15/12-12 Rev, 24/9-5 Volund, 35/8-1 Vega, 35/9-1R Gjøa and 6507/3-1 Alve discoveries. The potential for resources from possible future measures to increase oil recovery is now estimated at 140 million scm o.e., up 3 million scm o.e. compared with last year. The estimate for gas is 130 million scm o.e., an increase of 30 million scm o.e. from last year.

Undiscovered resources

Undiscovered resources are petroleum volumes which are expected to be present in defined play models, confirmed and unconfirmed, but which have not yet been proven through drilling (resource categories 8 and 9). The estimate of total undiscovered resources is 3.4 billion scm o.e., unchanged from last year.

The North Sea

A total of 7.2 billion scm o.e. has been proven in the North Sea, of which 4.1 billion scm o.e. has been produced. Remaining reserves are 2.5 billion scm o.e., of which 34 per cent is oil. Production from the North Sea in the past year was 197 million scm o.e. Remaining reserves in the North Sea were reduced by 133 million scm o.e. Two oil discoveries were made in one wellbore in the North Sea in 2006. The reason that contingent resources in discoveries were reduced by 87 million scm o.e is that the licensees have decided to submit PDOs for the 15/12-12 Rev, 24/9-5 Volund, 35/8-1 Vega and 35/9-1 R Gjøa discoveries in 2006, which means that these resources are thus counted as reserves. Undiscovered resources in the North Sea are expected to amount to about 1.2 billion scm o.e.

The Norwegian Sea

A total of 2.0 billion scm o.e. has been proven in the Norwegian Sea, of which 0.5 billion scm o.e. have been produced. Remaining reserves amount to about 1.0 billion scm o.e., of which 65 per cent is gas. Production in 2006 was 52 million scm o.e. Estimated remaining reserves have declined because the reserves in many of the fields in the Norwegian Sea have been adjusted downwards. One new gas discovery was made in the Norwegian Sea in 2006. The estimate for contingent resources in fields has increased by 42 million scm o.e because the licensees on several fields have initiated many new projects to improve recovery. The estimate for contingent resources in discoveries has been reduced by 10 million scm o.e. compared with last year's accounts, while the estimate for undiscovered resources in the Norwegian Sea was reduced by 25 million scm o.e.

The Barents Sea

0.25 billion scm o.e. has been proven in the Barents Sea. There is an increase in the estimate for contingent resources in fields and discoveries in the Barents Sea in the past year. The increase of 19 million scm o.e in contingent resources in fields is due to the fact that the resources in Snøhvit Nord and 7121/5-2 Beta are now reported together with the Snøhvit field, and not as contingent resources in discoveries. Consideration is also being given to developing the oil zone in Snøhvit. Contingent resources in discoveries have been increased as a result of three new oil discoveries in two wellbores in the Barents Sea in the past year. The estimate for undiscovered resources in the Barents Sea has increased by 40 million scm o.e.

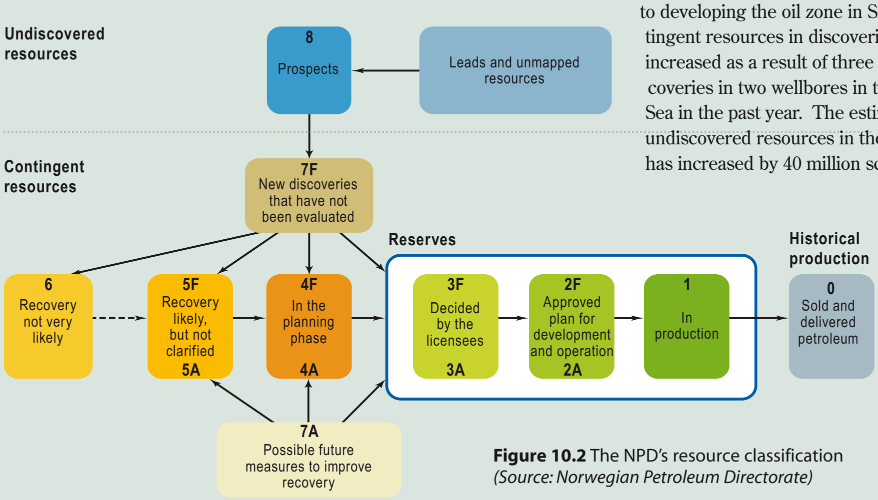


Figure 10.2 The NPD's resource classification
(Source: Norwegian Petroleum Directorate)

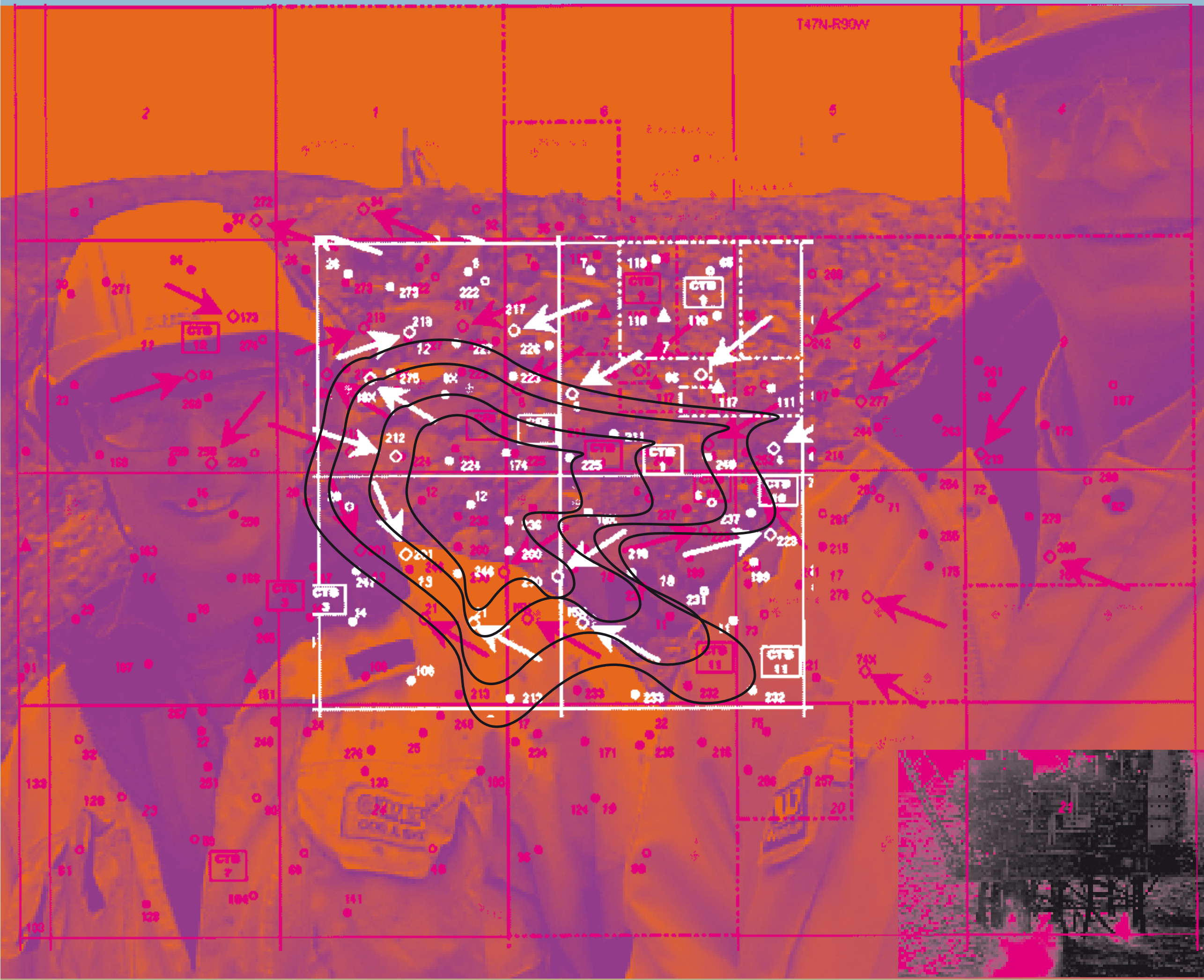
Table 10.1 Resource accounts per 31.12.2006

Total recoverable potential Project status category	Resource accounts per 31.12.2006 Oil mill scm	Gas bill scm	NGL mill tonnes	Cond mill scm	Total mill scm o.e.	Changes from 2005 Oil mill scm	Gas bill scm	NGL mill tonnes	Cond mill scm	Total mill scm o.e.
Produced	3155	1142	99	89	4573	137	88	9	8	249
Remaining reserves'	1075	2302	123	49	3659	-155	-56	-16	2	-239
Contingent resources in fields	375	166	20	5	585	65	11	3	0	82
Contingent resources in discoveries	152	424	22	35	654	14	-70	-8	-2	-73
Potential from improved recovery	140	130			270	3	30			33
Undiscovered	1260	1875		265	3400	100	-25		-75	0
Total	**6158**	**6040**	**263**	**442**	**13141**	**164**	**-23**	**-12**	**-67**	**51**
North Sea										
Produced	2778	1067	85	67	4073	110	73	6	3	197
Remaining reserves'	842	1509	71	8	2494	-115	-14	-5	4	-133
Contingent resources in fields	295	108	9	4	425	33	-10	-1	0	20
Contingent resources in discoveries	66	112	8	14	206	-21	-48	-7	-4	-87
Undiscovered	620	500		55	1175	5	0	0	-20	-15
Total	**4601**	**3297**	**172**	**148**	**8373**	**12**	**0**	**-7**	**-17**	**-18**
Norwegian Sea										
Produced	377	75	14	21	500	27	15	3	5	52
Remaining reserves'	233	632	45	22	975	-40	-42	-11	-2	-106
Contingent resources in fields	70	51	11	0	141	22	13	4	0	42
Contingent resources in discoveries	58	301	15	22	408	13	-24	-1	3	-10
Undiscovered	220	825		150	1195	-15	15	0	-25	-25
Total	**958**	**1884**	**85**	**215**	**3218**	**7**	**-23**	**-5**	**-20**	**-46**
Barents Sea										
Produced	0	0	0	0	0	0	0	0	0	0
Remaining reserves'	0	161	6	18	191	0	0	0	0	0
Contingent resources in fields	10	8	0	1	19	10	8	0	1	19
Contingent resources in discoveries	29	11	0	0	39	22	3	0	-1	24
Undiscovered	420	550		60	1030	110	-40	0	-30	40
Total	**459**	**729**	**6**	**79**	**1279**	**142**	**-29**	**0**	**-30**	**83**

' 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



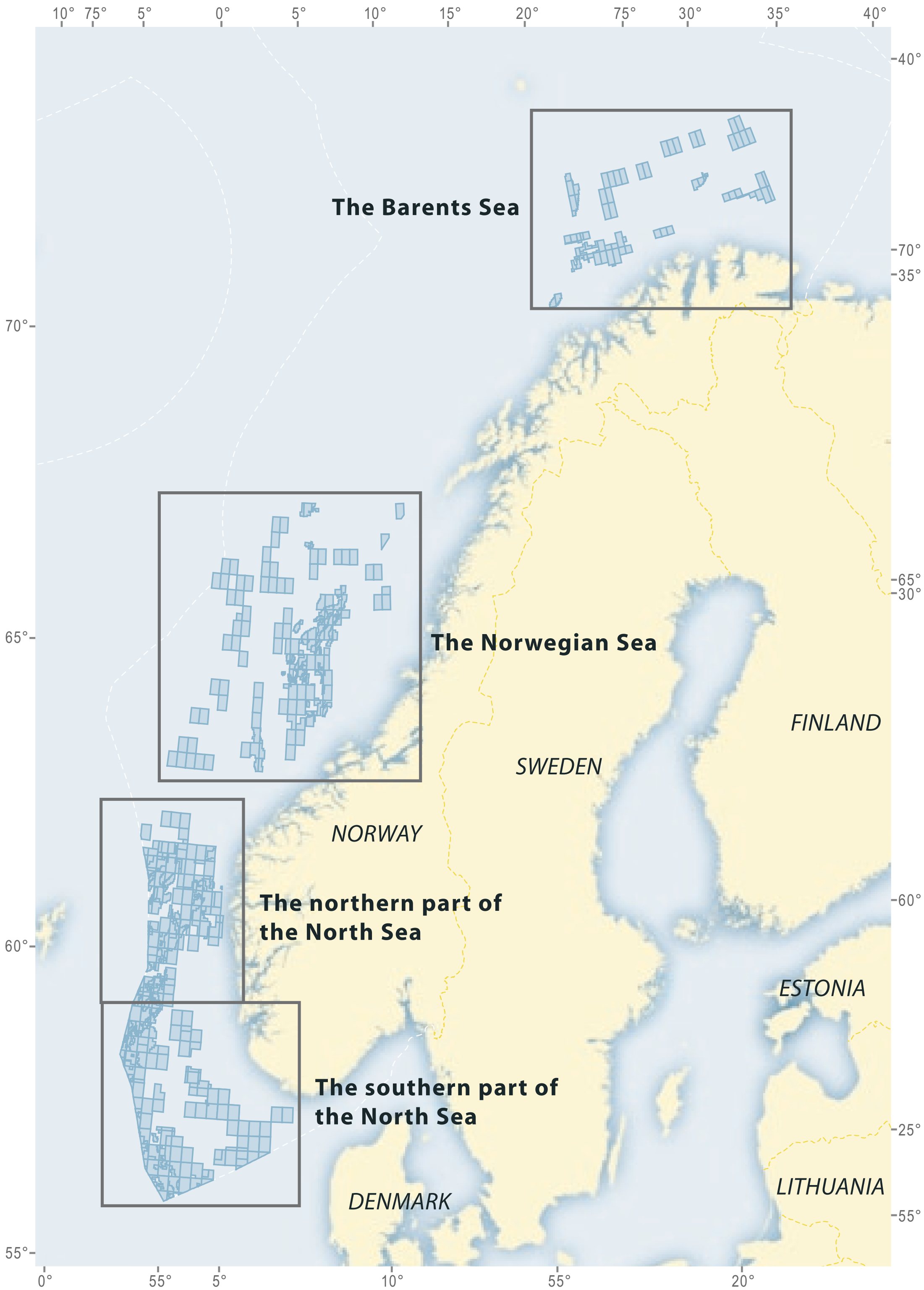


Figure 11.1 The Norwegian continental shelf

The southern part of the North Sea

The southern part of the North Sea became important for the country when Ekofisk, as the first Norwegian offshore field, came on stream in 1971. At present 25 fields are located in the area. Many of the fields have been shut down after production has ceased, but some of these are now being prepared for redevelopment, i.e. Yme and Mime. Ekofisk serves as a hub for petroleum operations in this area, with several fields utilising the infrastructure for further transport in the Norpipe system. From Ekofisk, oil is exported by pipeline to Teesside in the United Kingdom, while gas is sent by pipeline to Emden in Germany. The Sleipner fields in the northern part of the area serve as an important hub for the gas transport system on the Norwegian continental shelf.

Although there has been production from the southern part of the North Sea for 35 years, remaining resources in the area are substantial, 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 at least another three decades.

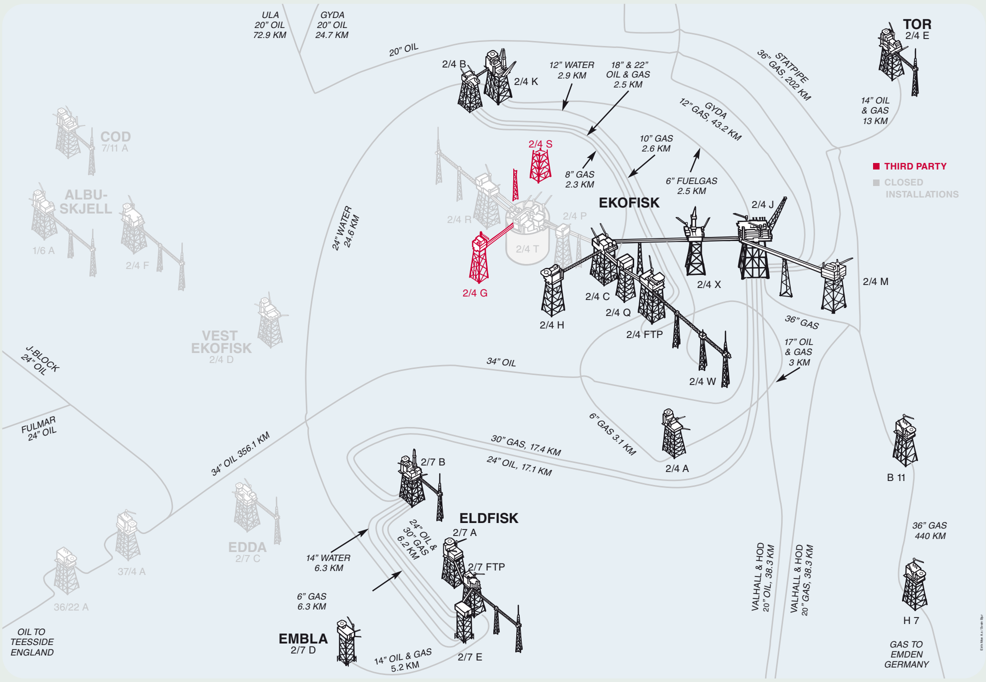


Figure 11.2 Facilities in the Ekofisk area

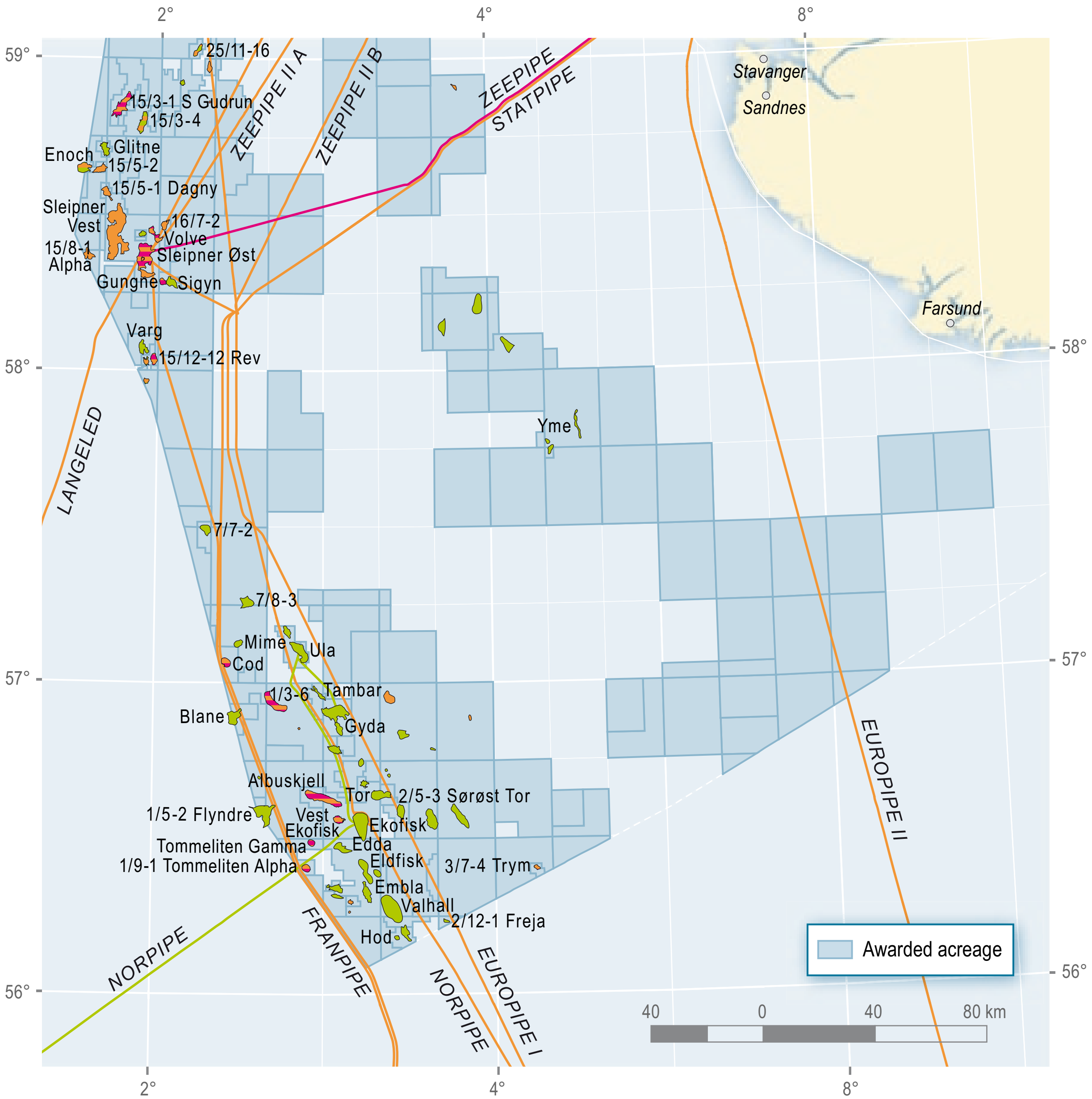


Figure 11.3 The southern part of the North Sea

The northern part of the North Sea

The northern part of the North Sea encompasses the three main areas Tampen, Oseberg /Troll and Balder /Heimdal. At present 35 fields are located in this part of the North Sea, and more will be developed over the next years. The gas fields in the Frigg area have been shut down after ceased production, but some of these may be redeveloped at a later stage. The Tampen area holds many of the largest oil fields on the Norwegian continental shelf, such as Statfjord, Snorre and Gullfaks. Although Tampen is a mature petroleum province, there is still a substantial resource potential, and production from this area is expected to continue for at least another 20 years.

Troll plays a major role for gas supplies from the Norwegian continental shelf, and it will remain the main source of Norwegian gas exports throughout this century. Significant oil production has also developed on the Troll field. The Oseberg area includes Brage and Veslefrikk, in addition to the Oseberg fields. Oil production from the Oseberg area is declining, but will remain important for many years to come. Heimdal is a a gas hub with processing services for other fields.

Oil and gas from fields in the northern part of the North Sea are transported by tankers or by pipeline to land facilities in Norway and the United Kingdom.

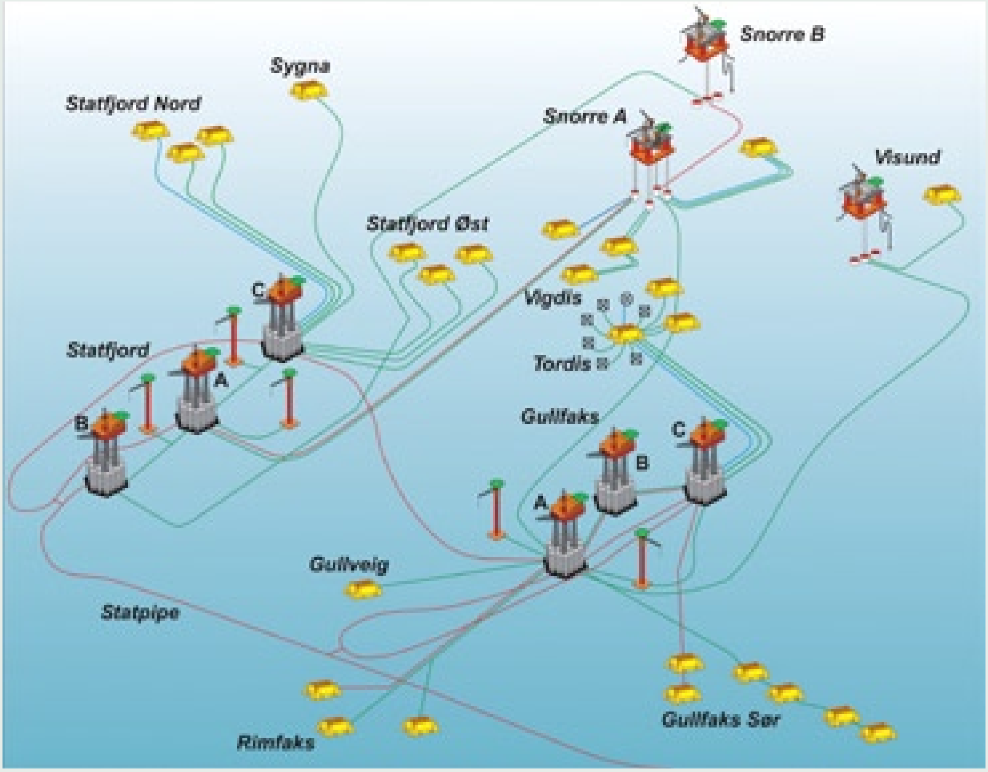


Figure 11.4 The Tampen area
Source: Statoil

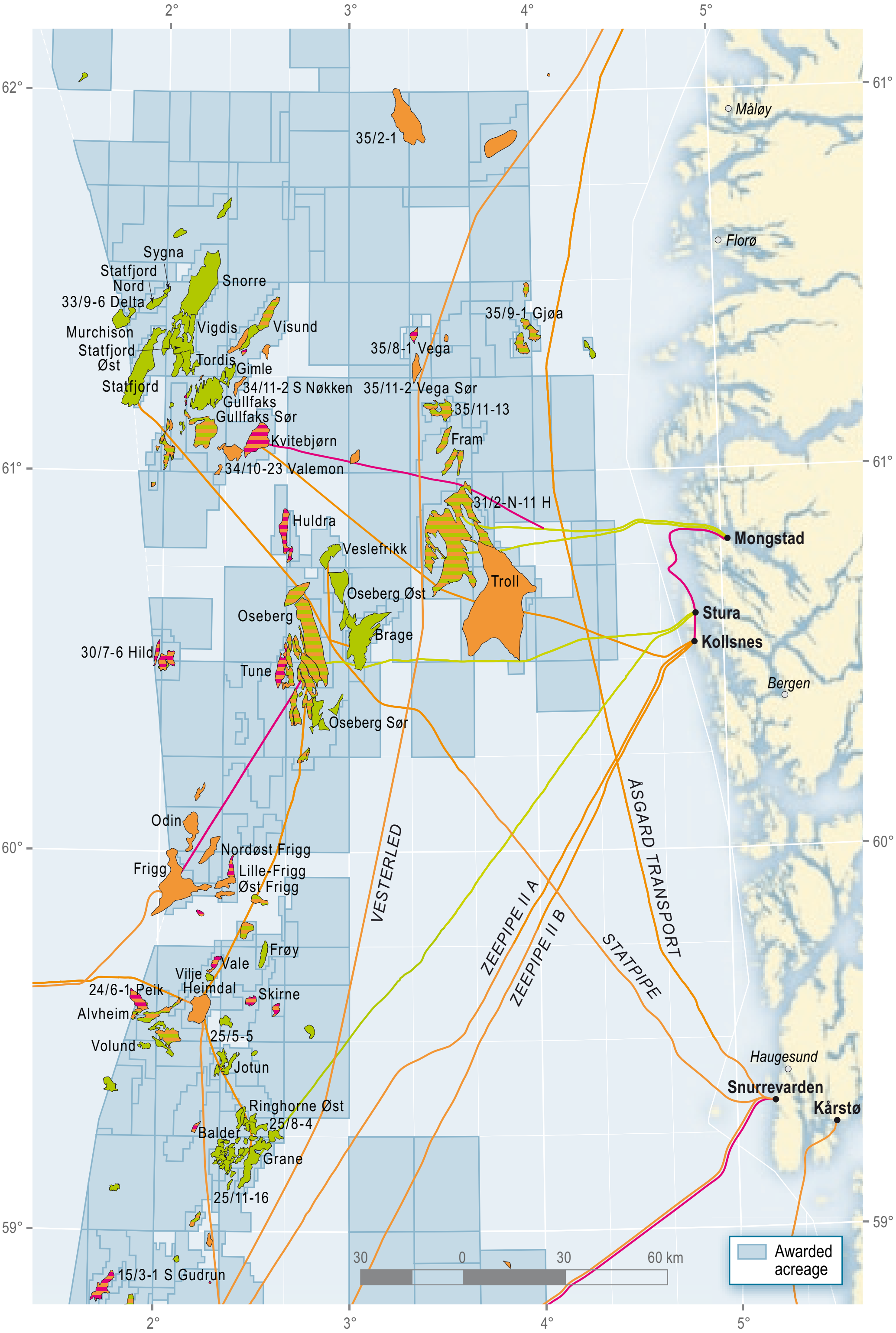


Figure 11.5 The northern part of the North Sea

The Norwegian Sea

The Norwegian Sea is a less mature petroleum province than the North Sea. There are presently 10 fields in the area and more will be developed over the coming years. No fields have ceased production. Draugen was the first field to come on stream, in 1993. There are significant gas reserves in the Norwegian Sea. The Åsgard field and the Åsgard Transport represent the key processing and gas export infrastructure for the Norwegian Sea. The gas from Åsgard, Kristin, Mikkel, Norne and Draugen is transported in the Åsgard Transport pipeline to Kårstø in Rogaland, and gas from Heidrun is transported in Haltenpipe to Tjeldbergodden in Møre og Romsdal. The gas from Ormen Lange will be routed through a new 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.

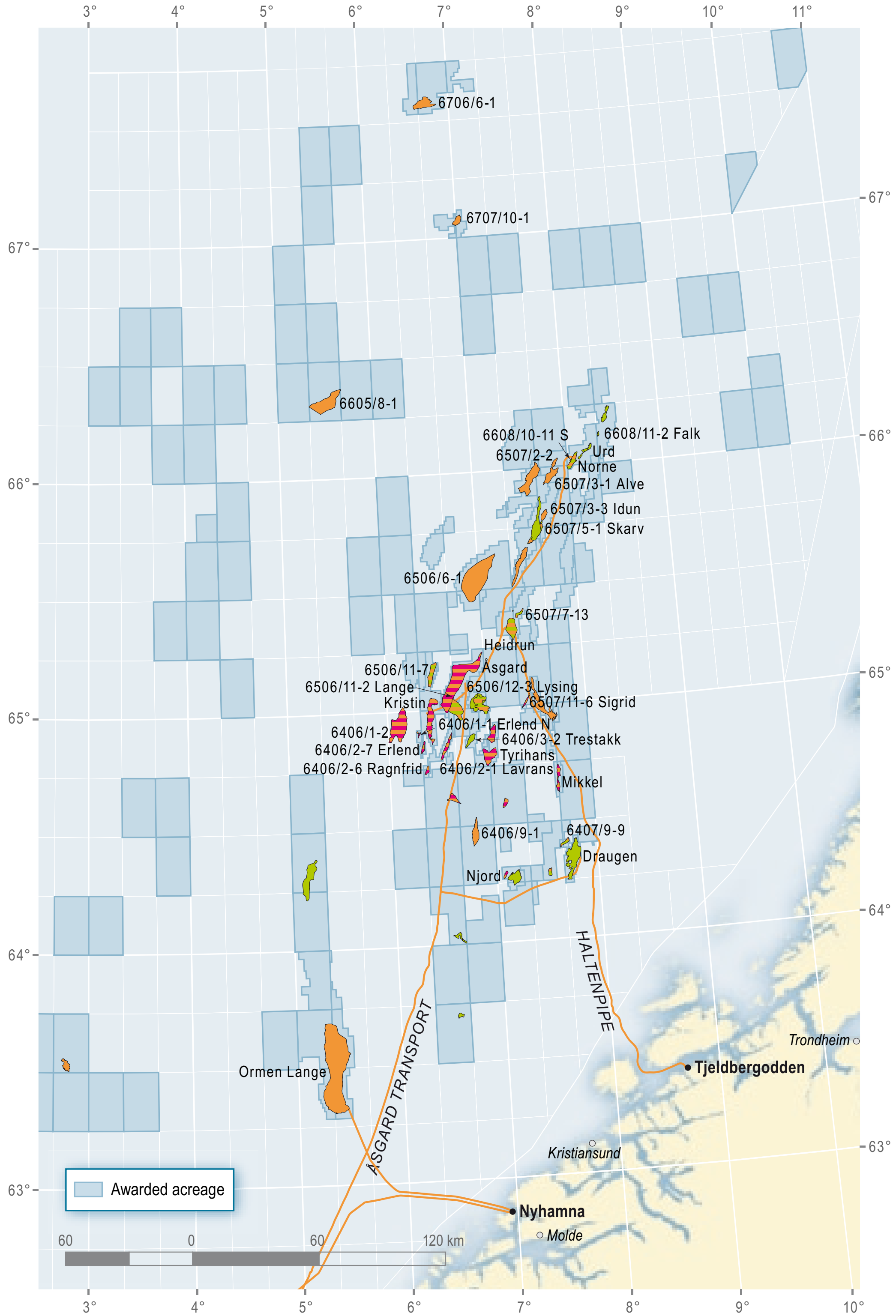


Figure 11.6 The Norwegian Sea

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.

Because interests are quoted with only two decimal places, licensee holdings in some of the fields may not add up to 100 per cent. Participating interests are shown as of 31 December 2006.

"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 The Norwegian Petroleum Directorate's resource classification.

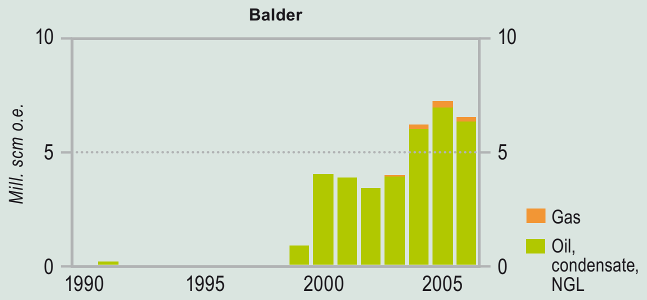
"Recoverable reserves remaining at 31 December 2006" refers to reserves in resource categories 1, 2 and 3 in the Norwegian Petroleum Directorate's resource classification.

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

Expected 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 – 13:

Thanks to A/S Norske Shell, BP Norge AS, ConocoPhillips Scandinavia AS, ExxonMobil Exploration and Production Norway A/S, Marathon Petroleum Norge AS, Norsk Hydro Produksjon AS, Statoil ASA, Talisman Energy Norge AS og Total E&P Norge AS for use of pictures and illustrations of facilities.



Balder

Block and production licence	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:** 54,7 million scm oil 2,0 billion scm gas	**Remaining as of 31.12.2006** 19,0 million scm oil 1,3 billion scm gas
Production	**Estimated production in 2007:** Oil: 92 000 barrels/day Gas: 0,29 billion scm	
Investment	Total investment is expected to be NOK 24,5 billion (2007 values) NOK 23,8 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

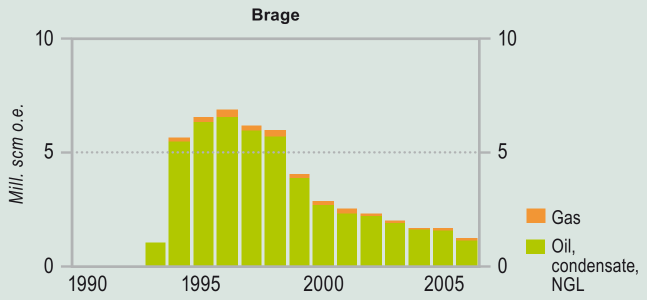
Development:
Balder is an oil field in the northern part of the North Sea. The sea depth in the area is 125 metres. The field has been developed with subsea wells tied back to the accommodation, production and storage vessel, Balder FPU, where oil and gas are processed. The Ringhorne discovery, which is part of the Balder field, has been developed with a combined accommodation, drilling and wellhead facility, which is also tied back to Balder FPU, and a subsea template with one oil production well and one water injection well. 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:
Balder contains several separate accumulations of Tertiary sandstones. The Ringhorne development includes several reservoirs of the same type as in Balder and in addition a main reservoir of Jurassic sandstones.

Recovery strategy:
Balder and the Ringhorne deposit are recovered by aquifer drive, as well as injection of produced water and partly by gas injection.

Transport:
Oil and gas from the Jurassic reservoir at Ringhorne are transported to Jotun for processing, while oil from the Tertiary reservoirs is routed to Balder. Gas from Balder is transported to Jotun for gas lift and export via Statpipe. In periods with reduced gas export excess gas may be injected in Balder.

Status
One new production well was drilled in 2006 and two new wells are planned from the Ringhorne facility in 2007. New seismic acquired in 2006 provides basis for planning of new well targets.



Brage

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Altinex Oil AS	12,26 %
	Endeavour Energy Norge AS	4,44 %
	Norsk Hydro Produksjon AS	20,00 %
	Petoro AS	14,26 %
	Revus Energy ASA	2,50 %
	Statoil ASA	12,70 %
	Talisman Energy Norge AS	33,84 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	50,8 million scm oil	3,5 million scm oil
	2,6 billion scm gas	0,2 billion scm gas
	0,8 million tonnes NGL	
Production	**Estimated production in 2007:** Oil: 16 000 barrels/day Gas: 0,13 billion scm	
Investment	Total investment is expected to be NOK 19,0 billion (2007 values) NOK 18,0 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

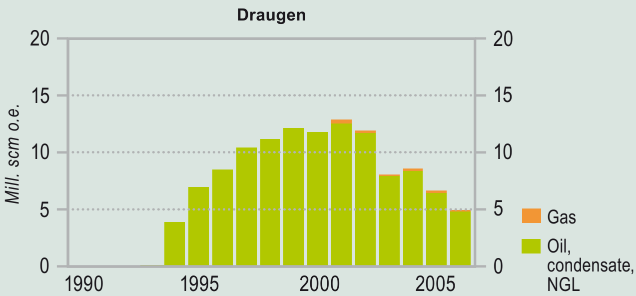
Development:
Brage is an oil field east of Oseberg in the northern part of the North Sea. The sea depth in the area is 140 metres. Brage has been developed with a fixed integrated production, drilling and accommodation facility with a steel jacket. Test production from the Sognefjord formation took place in 1997, and this deposit was approved for development on 20.10.1998.

Reservoir:
The Brage field consists of sandstone reservoirs in the Lower Jurassic Statfjord formation, the Middle Jurassic Fensfjord formation and Upper Jurassic Sognefjord formation.

Recovery strategy:
The recovery mechanism in the Statfjord formation is water injection, and in the Fensfjord formation both water and gas injection. The wells in the Fensfjord formation are recovered by gas lift. The Sognefjord formation is recovered with pressure depletion, but a gas injection well is planned to be drilled in 2008

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

Status:
Brage is in tail production, and work is proceeding to find new ways of increasing recovery from the field. The water injection capacity on the field will be expanded and there are plans for new wells. Adding chemicals to the injection water to improve water flow is one of the methods being evaluated.



Draugen

Block and production licence	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 31.12.2006**
	138,7 million scm oil / 25,1 million scm oil
	1,5 billion scm gas / 0,3 billion scm gas
	2,4 million tonnes NGL / 0,7 million tonnes NGL
Production	**Estimated production in 2007:**
	Oil: 56 000 barrels/day Gas: 0,08 billion scm, NGL:0,12 million tonnes
Investment	Total investment is expected to be NOK 27,5 billion (2007 values)
	NOK 26,5 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Kristiansund
Main supply base	Kristiansund

Development:
Draugen is an oil field in the Norwegian Sea with 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 flowlines connect the facility to a floating loading buoy. The Garn Vest and Rogn Sør deposits have been developed with a total of five subsea wells connected to the main facility at Draugen. The field has six subsea water injection wells. Additional resources in the Garn Vest structure came on stream in December 2001, while development of additional resources at the Rogn Sør structure were approved in the spring of 2001, coming on stream in January 2003.

Reservoir:
The main reservoir consists of Upper Jurassic sandstones in the Rogn formation. In addition, the Garn formation in the west of the field is in production. The reservoirs are relatively homogenous, with good reservoir characteristics.

Recovery strategy:
The field is produced with pressure maintenance through water injection, and gas lift is installed in the wells. Large scale gas/CO_2 injection is being considered.

Transport:
The oil is exported by tankers. The associated gas is sent through the Åsgard Transport pipeline to Kårstø.

Status:
Oil production came off plateau around 2003, and the quantity of produced water is increasing. Various measures to increase recovery are being evaluated. New production wells will be drilled on Draugen in 2007/2008. The licensees are preparing extensive plans for CO_2 injection and gas injection.

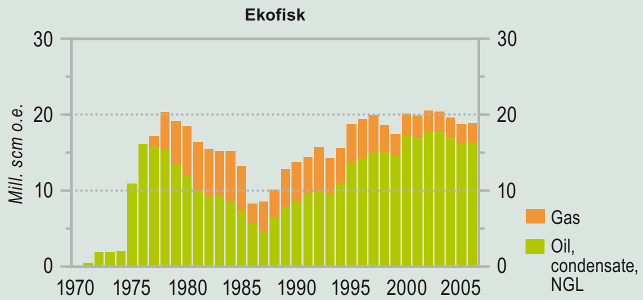
Ekofisk

Block and production licence	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 %
	Norsk Hydro Produksjon AS	6,65 %
	Petoro AS	5,00 %
	Statoil ASA	0,95 %
	Total E&P Norge AS	39,90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	540,3 million scm oil	162,8 million scm oil
	154,2 billion scm gas	22,9 billion scm gas
	14,6 million tonnes NGL	2,8 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 236 000 barrels/day Gas: 2,30 billion scm, NGL:0,26 million tonnes	
Investment	Total investment is expected to be NOK 156,7 billion (2007 values)	
	NOK 118,6 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Ekofisk is located in the south of the North Sea. The sea depth in the area is between 70-75 metres. Production at Ekofisk began in 1971 from the jack-up facility Gulftide. During the first years, the field produced to tankers from four wells, until the concrete tank was in place 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 wellhead facility for water injection Ekofisk W, the drilling and production facility Ekofisk X ,the processing facility Ekofisk J and the production and processing facility Ekofisk M. From the wellhead facilities Ekofisk A and B, south and north of the field, production goes to the riser facility Ekofisk FTP at the Ekofisk Centre. Ekofisk B is connected by bridge to Ekofisk K, which is the main facility for water injection.

Production from the Ekofisk field was formally started in 1971. Approval in principle of the technical system for development of the Ekofisk field was granted in 1972. Water injection was approved on 20.12.1983, Ekofisk II was approved on 09.11.1994, Ekofisk Growth was approved on 06.06.2003.

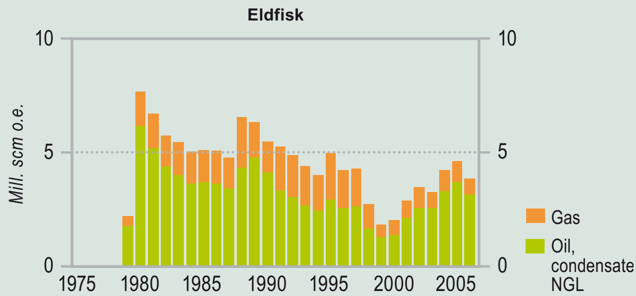
Reservoir:
The Ekofisk field produces from the Ekofisk and Tor chalk formations in the Upper Paleocene and Lower Cretaceous ages. The reservoir rocks are fine-grained and dense, but pervasive fractures increase flow.



Recovery strategy:
Ekofisk was originally developed with pressure depletion as the drive mechanism. 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 estimated reserves have been adjusted upwards correspondingly. In addition to the water injection, compaction of the soft chalk provides extra force to drainage of the field. This effect is reinforced because the injected water contributes to weakening the chalk.

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

Status:
Production from Ekofisk is expected to maintain its current high level for a few more years. This is mainly due to increased numbers of wells and increased processing capacity from the new facility Ekofisk M. In relation to current plans, there are good chances for further increase in the reserves when water injection is optimised. High activity is expected to continue at the field over the coming years. It has been decided to connect Ekofisk B to Ekofisk M in 2007. The plan is to shut down production from Ekofisk A, when has not yet been decided. Two new facilities on the field are being evaluated, a new accommodation facility and a new production facility. Continuous drilling is, under the current strategy, the key to high recovery levels. In addition to efforts to optimise short and long-term production, work on cleaning and disposal of disused facilities is in progress. So far, the deck facility on Ekofisk T has been dismantled and transported to land.



Eldfisk

Block and production licence	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 %
	Norsk Hydro Produksjon AS	6,65 %
	Petoro AS	5,00 %
	Statoil ASA	0,95 %
	Total E&P Norge AS	39,90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	132,6 million scm oil	49,0 million scm oil
	42,6 billion scm gas	6,1 billion scm gas
	4,3 million tonnes NGL	0,7 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 46 000 barrels/day Gas: 0,61 billion scm, NGL:0,06 million tonnes	
Investment	Total investment is expected to be NOK 86,0 billion (2007 values)	
	NOK 48,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

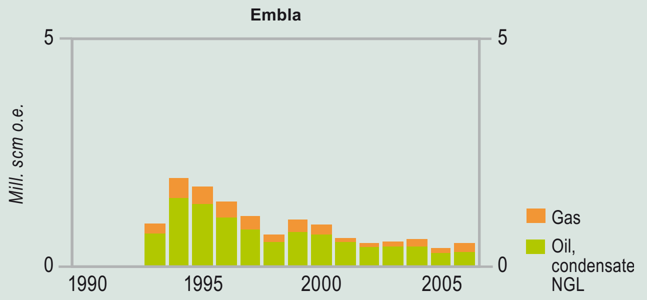
Development:
Eldfisk is located in the southern part of the North Sea, south of Ekofisk. The sea depth in the area is 70-75 metres. The original Eldfisk development consisted of three facilities. Eldfisk B is a combined drilling, wellhead and process facility, while Eldfisk A and FTP are wellhead and process facilities connected by a bridge. Eldfisk A also has drilling facilities. In 1999, a new water injection facility, Ekofisk E, was installed. The facility also supplies the Ekofisk field with some injection water through a pipeline from Eldfisk to Ekofisk K. Eldfisk water injection was approved on 12.12.1997. Upgrading of the capacity of Eldfisk was approved on 06.06.2003, as part of the plan for Ekofisk Growth.

Reservoir:
The Eldfisk field produces from the Ekofisk, Tor and Hod chalk formations from the Lower Paleocene and Upper Cretaceous ages. The reservoir rock is fine-grained and dense, but pervasive fractures increase flow. The field consists of three structures: Alpha, Bravo and East Eldfisk.

Recovery strategy:
Eldfisk was originally developed with pressure depletion as the drive mechanism. In 1999, water injection began at the field, based on horizontal injection wells. Gas is also injected in periods.

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 the NGL fractions, is routed by pipeline to Teesside.

Status:
A study is in progress to determine measures to increase recovery from Eldfisk. These measures may imply new facilities.



Embla

Block and production licence	Block 2/7 - production licence 018, awarded 1965	
Discovered	1988	
Development approval	14.12.1990	
On stream	12.05.1993	
Operator	ConocoPhillips Skandinavia AS	
Licensees	ConocoPhillips Skandinavia AS	35,11 %
	Eni Norge AS	12,39 %
	Norsk Hydro Produksjon AS	6,65 %
	Petoro AS	5,00 %
	Statoil ASA	0,95 %
	Total E&P Norge AS	39,90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	11,3 million scm oil	2,1 million scm oil
	5,1 billion scm gas	2,0 billion scm gas
	0,5 million tonnes NGL	0,2 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 3 000 barrels/day Gas: 0,12 billion scm, NGL:0,01 million tonnes	
Investment	Total investment is expected to be NOK 4,2 billion (2007 values)	
	NOK 4,1 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

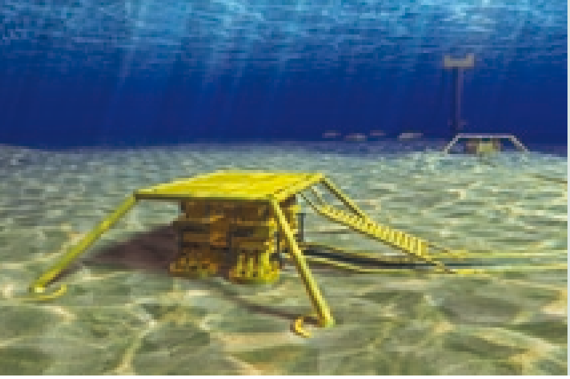
Development:
Embla is located close to Eldfisk in the southern part of the North Sea. The field has been developed with an unmanned wellhead facility which is remotely controlled from Eldfisk. The sea depth in the area is 70-75 metres. The amended PDO for Embla was approved on 25.04.1995.

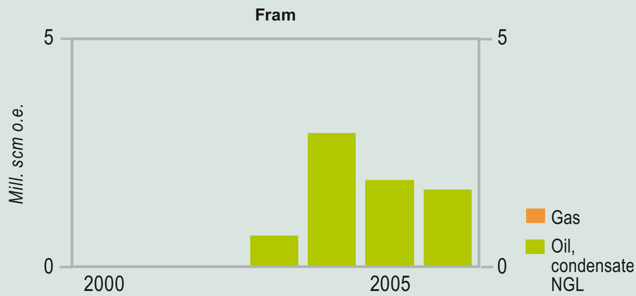
Reservoir:
The Embla field produces from a segmented sandstone reservoir from the Devonian and Permian ages. The reservoir is more than 4 000 metres below seabed.

Recovery strategy:
Embla is produced by pressure depletion.

Transport:
Oil and gas are transported to Eldfisk 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 the NGL fractions, is routed via pipeline to Teesside.

Status:
One additional well was drilled on Embla in 2005, but the results were below expectations. Without drilling more wells, production from Embla will decrease.





Fram

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Gaz de France Norge AS	15,00 %
	Idemitsu Petroleum Norge AS	15,00 %
	Mobil Development Norway AS	25,00 %
	Norsk Hydro Produksjon AS	25,00 %
	Statoil ASA	20,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	21,0 million scm oil	13,9 million scm oil
	9,8 billion scm gas	9,8 billion scm gas
	0,2 million tonnes NGL	0,2 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 37 000 barrels/day Gas: 0,23 billion scm	
Investment	Total investment is expected to be NOK 8,7 billion (2007 values)	
	NOK 6,4 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

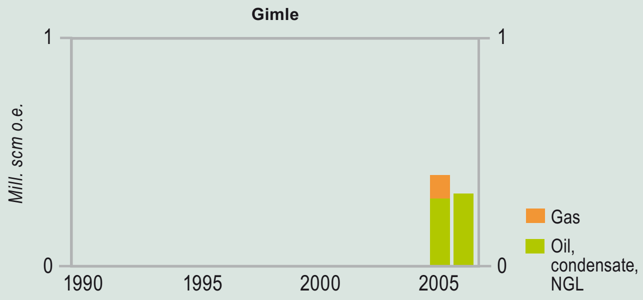
Development:
Fram is an oilfield located in the northern part of the North Sea, about 20 kilometres north of Troll. The sea depth in the area is 350 metres. The Fram Vest deposit is developed by two subsea templates tied back to Troll C. The gas is separated from the liquid on Troll C and reinjected into the Fram Vest reservoir. The development of Fram Øst deposit was approved on 22.04.2005. The 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 turbidity sandstones in the Draupne formation and shallow marine sandstones in the Sognefjord formation, and partly sandstones in the Etive formation of Middle Jurassic age. The reservoirs lie in several isolated rotated fault blocks and contain oil with overlying gas cap.

Recovery strategy:
Production from the Fram Vest deposit takes place with gas injection as pressure support for some more years. Gas breakthrough in one production well has however,resulted in a reevaluation of the gas injection strategy. The Fram Øst deposit in the Sognefjord formation is recovered by water injection as pressure support and by gas lift. The Fram Øst deposit in the Etive formation will be recovered by gas expansion drive.

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:
Several production wells will be drilled on the Fram Øst deposit and one additional well in the Fram Vest deposit is being considered. The production period for Fram is dependent on the lifetime of Troll C.



Gimle

Block and production licence	Block 34/7 - production licence 120 B, awarded 2006 Block 34/8 – production licence 120 B, awarded 2006 Block 34/10 - production licence 050 DS, awarded 2006	
Discovered	2004	
Development approval	18.05.2006	
On stream	19.05.2006	
Operator	Statoil ASA	
Licensees	Norsk Hydro Produksjon AS	17,90 %
	Norske ConocoPhillips AS	5,79 %
	Petoro AS	24,19 %
	Statoil ASA	47,23 %
	Total E&P Norge AS	4,90 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	4,0 million scm oil	3,5 million scm oil
	0,8 billion scm gas	0,7 billion scm gas
	0,1 million tonnes NGL	0,1 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 10 000 barrels/day Gas: 0,11 billion scm, NGL: 0,01 million tonnes	
Investment	Total investment is expected to be NOK 0,8 billion (2007 values) NOK 0,4 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	

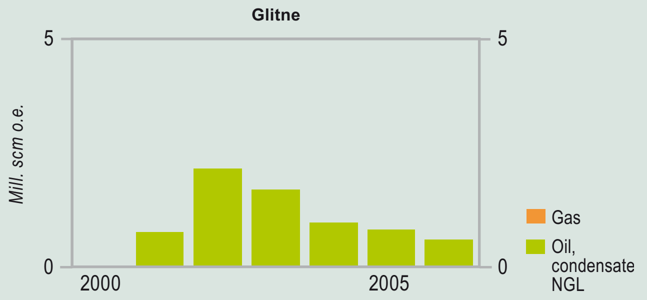
Development:
Gimle is a small oil field adjacent to Gullfaks in the northern part of the North Sea. The field was proven in 2004 by well 34/10-48 S drilled from the Gullfaks C facility. Test production on Gimle took place in 2005 before development was decided.

Reservoir:
The reservoir in Gimle consists of sandstones in the Tarbert formation of Middle Jurassic age, in a downfaulted structure northeast of Gullfaks. Reservoir characteristics are very good with only a few minor faults.

Recovery strategy:
Gimle will be recovered by water injection.

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

Status:
Gimle was partitioned off as separate production licences in 2006. According to plan a water injection well will be drilled early in 2007 and a second production well in 2007/2008.



Glitne

Block and production licence	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 ASA	
Licensees	DONG E&P Norge AS Det Norske Oljeselskap AS Statoil ASA Total E&P Norge AS	9,30 % 10,00 % 58,90 % 21,80 %
Recoverable reserves	**Original:** 8,3 million scm oil	**Remaining as of 31.12.2006** 1,3 million scm oil
Production	**Estimated production in 2007:** Oil: 8 000 barrels/day	
Investment	Total investment is expected to be NOK 2,6 billion (2007 values) NOK 2,2 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

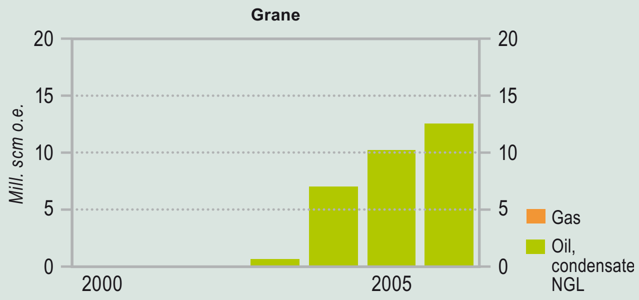
Development:
Glitne is an oilfield in the southern part of the North Sea, 40 kilometres north of the Sleipner area. The sea depth in the area is 110 metres. The development consists of four production wells and a water injection well tied back to the floating production, storage and offloading vessel, Petrojarl 1.

Reservoir:
The reservoir consists of several separate sand sheets of deep-marine fan deposits in the upper Heimdal formation.

Recovery strategy:
Glitne is recovered by pressure support partly from reinjection of produced water in one well and partly from a large aquifer. In addition associated gas is used for gas lift in the wells, while excess gas is injected in the Utsira formation above the reservoir.

Transport:
Oil from Glitne is processed and stored on board the production vessel. The oil is exported by shuttle tankers.

Status:
One new well will be drilled on the flank of Glitne in 2007 and an additional well will be considered. Increased reserves may extend the lifetime of the field.



Grane

Block and production licence	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000
Discovered	1991
Development approval	14.06.2000
On stream	23.09.2003
Operator	Norsk Hydro Produksjon AS
Licensees	ExxonMobil Exploration & Production Norway AS 25,60 % Norsk Hydro Produksjon AS 38,00 % Norske ConocoPhillips AS 6,40 % Petoro AS 30,00 %
Recoverable reserves	**Original:** 112,4 million scm oil **Remaining as of 31.12.2006** 81,6 million scm oil
Production	**Estimated production in 2007:** Oil: 200 000 barrels/day
Investment	Total investment is expected to be NOK 21,4 billion (2007 values) NOK 15,6 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Bergen
Main supply base	Mongstad

Development:
Grane is an oil field located to the east of the Balder field in the northern part of the North Sea. It has been developed with an integrated accommodation, drilling and processing facility with a fixed steel jacket. The facility has 40 well slots. The sea depth in the area is 127 metres.

Reservoir:
The field consists of one main reservoir structure and some additional segments. The reservoir consists of Tertiary sandstones in the Heimdal formation with good reservoir characteristics. The oil has high viscosity. Some oil is also present in the Lista formation above the main structure.

Recovery strategy:
The recovery mechanism is gas injection at the top of the structure, and long-range horizontal production wells at the bottom of the oil zone. The oil in the Lista reservoir will probably be recovered as a result of the gas injection in the Heimdal formation.

Transport:
Oil from Grane is sent by pipeline to the Sture terminal where it is stored and shipped. Injection gas is imported to Grane through a pipeline from the Heimdal facility.

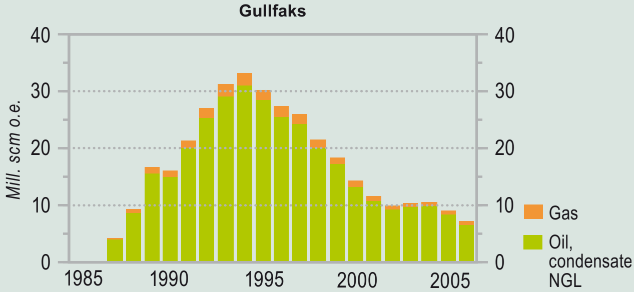
Status:
Several new wells have been drilled on Grane in 2006 and additional multi-branch wells are planned. A recent study indicates a potential to accelerate the planned water injection in the reservoir. The first water injection well is planned in 2008.

Gullfaks

Block and production licence	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 ASA	
Licensees	Norsk Hydro Produksjon AS Petoro AS Statoil ASA	9,00 % 30,00 % 61,00 %
Recoverable reserves	**Original:** 356,6 million scm oil 24,3 billion scm gas 2,7 million tonnes NGL	**Remaining as of 31.12.2006** 27,4 million scm oil 2,1 billion scm gas 0,2 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 111 000 barrels/day Gas: 0,45 billion scm, NGL: 0,06 million tonnes	
Investment	Total investment is expected to be NOK 118,7 billion (2007 values) NOK 109,9 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

Development:
Gullfaks is located in the Tampen area in the northern part of the North Sea. The sea depth in the area is 130 to 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. With this plan, recovery of the resources in the area can be accomplished more efficiently in the future.

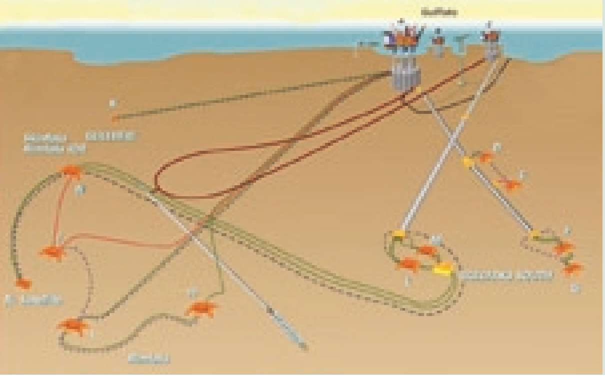
Reservoir:
The Gullfaks reservoirs consist of Middle Jurassic sandstones in the Brent group, and Lower Jurassic and Upper Triassic sandstones in the Cook, Statfjord and Lunde formations. The reservoirs are 1 700-2 000 m below the sea level. The Gullfaks reservoirs are located in rotated fault blocks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



Recovery strategy:
Gullfaks is an oil field, and the drive mechanisms for recovery are mainly pressure support using water injection, gas injection or water/alternating gas injection (WAG). The drive mechanism varies between the various 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 reinjected 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 the decline phase. 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 circulation. A new project has also been initiated, Gullfaks towards 2030, to evaluate necessary facility upgrades for lifetime extension towards 2030.

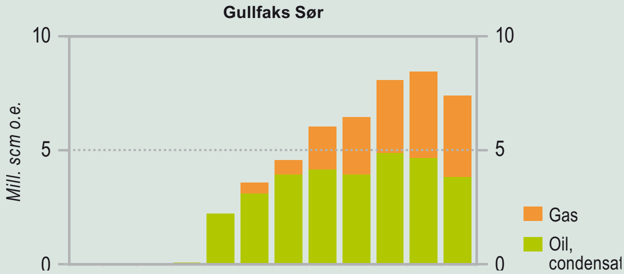


Gullfaks Sør

Block and production licence	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 ASA	
Licensees	Norsk Hydro Produksjon AS Petoro AS Statoil ASA	9,00 % 30,00 % 61,00 %
Recoverable reserves	**Original:** 47,9 million scm oil 42,6 billion scm gas 5,1 million tonnes NGL	**Remaining as of 31.12.2006** 20,7 million scm oil 26,4 billion scm gas 3,2 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 63 000 barrels/day Gas: 2,94 billion scm, NGL: 0,38 million tonnes	
Investment	Total investment is expected to be NOK 33,3 billion (2007 values) NOK 29,0 billion have been invested as of 31.12.2006 (2007 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 eleven subsea templates tied back to the Gullfaks A and Gullfaks C facilities. The Gullfaks Sør deposits have 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. 34/10-47 Gulltopp was discovered in 2002 and included in Gullfaks Sør in 2004. Gulltopp will be 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. The Skinfaks discovery is now included in Gullfaks Sør and production will commence in 2007.

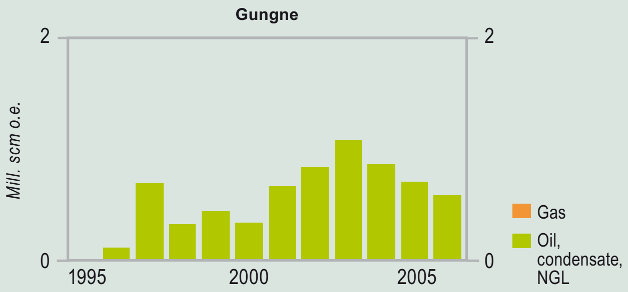
Reservoir:
The Gullfaks Sør reservoirs consist of Middle Jurassic sandstones in the Brent group and Lower Jurassic and Upper Triassic sandstones in the Cook, Statfjord and Lunde formations. Only the Brent and Statfjord reservoirs are currently developed. The reservoirs lie 2 400-3 400 metres below the seabed, 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 Skinfaks, Rimfaks, Gullveig and Gulltopp deposits however show good reservoir characteristics.



Recovery strategy:
Recovery of oil and condensate from the Gullfaks Sør deposits is partly driven by pressure support from gas injection, and partly by pressure depletion. Rimfaks Brent is produced using full pressure maintenance by gas injection whereas Gullfaks Sør and the Statfjord formation in Rimfaks have partial gas injection. Recovery from Gullveig is by pressure depletion, and the production is also affected by the production at Tordis and Gullfaks. Gulltopp and Skinfaks will be produced using gas lift.

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

Status:
New production and injection wells in recent years have shown that more reserves can be recovered from the Gullfaks Sør deposits. A project, Gullfaks Satellite Late Phase, is established in order to plan for a future gas phase for the deposits now mainly recovering oil.



Gungne

Block and production licence	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 ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	28,00 %
	Norsk Hydro Produksjon AS	9,40 %
	Statoil ASA	52,60 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006***
	12,5 billion scm gas	12,5 billion scm gas
	1,6 million tonnes NGL	0,3 million tonnes NGL
	4,4 million scm condensate	0,4 million scm condensate
Production	Estimated production in 2007:	
	Gas: 1,29 billion scm, NGL: 0,15 million tonnes, Condensate: 0,35 million scm	
Investment	Total investment is expected to be NOK 1,4 billion (2007 values)	
	NOK 1,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

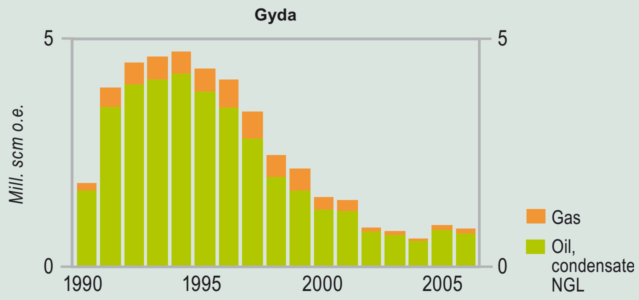
** The remaining gas reserves are shown as equal to the original because gas production from Gungne, Sleipner Vest and Sleipner Øst are measured together.*

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

Reservoir:
Gungne produces mainly from sandstone reservoirs in the Skagerrak formation of Triassic age. The reservoir characteristics are generally good, but the reservoir is segmented and lateral, continuous shale layers act as barriers.

Recovery strategy:
Gungne produces using pressure depletion as the drive mechanism.

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 the Zeepipe to Zeebrugge.



Gyda

Block and production licence	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 31.12.2006**
	38,6 million scm oil / 5,1 million scm oil
	6,2 billion scm gas / 0,6 billion scm gas
	1,9 million tonnes NGL / 0,1 million tonnes NGL
Production	**Estimated production in 2007:**
	Oil: 13 000 barrels/day Gas: 0,17 billion scm, NGL: 0,03 million tonnes
Investment	Total investment is expected to be NOK 15,8 billion (2007 values)
	NOK 14,7 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Stavanger
Main supply base	Tananger

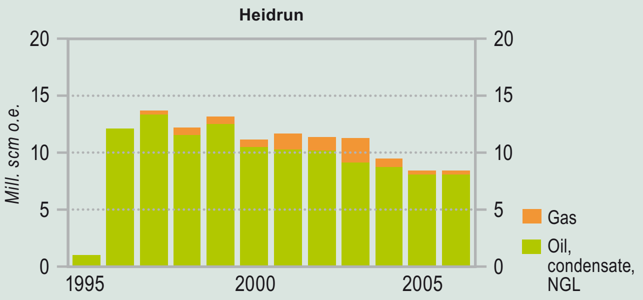
Development:
The Gyda field is located between Ula and Ekofisk in the southern part of the North Sea. It has been developed with a combined drilling, accommodation and processing facility with a steel jacket. The sea depth in the area is 66 metres.

Reservoir:
Gyda consists of three reservoir areas of Upper Jurassic sandstones.

Recovery strategy:
The field produces with water injection as the main drive mechanism. From 2006 produced water is also being reinjected into the reservoir for pressure support.

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

Status:
The production from Gyda has been lower than expected due to well problems causing delays in the drilling program. Several new wells are planned to be drilled to prolong the production from Gyda. A pilot to evaluate the potential of gas lift is started in 2007.



Heidrun

Block and production licence	Block 6507/8 - production licence 124, awarded 1986 Block 6707/7 - production licence 095, awarded 1986	
Discovered	1985	
Development approval	14.05.1991 by the Storting	
On stream	18.10.1995	
Operator	Statoil ASA	
Licensees	Eni Norge AS	5,12 %
	Norske ConocoPhillips AS	24,31 %
	Petoro AS	58,16 %
	Statoil ASA	12,41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	180,0 million scm oil	64,3 million scm oil
	41,8 billion scm gas	33,5 billion scm gas
	2,3 million tonnes NGL	1,9 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 125 000 barrels/day Gas: 0,11 billion scm, NGL: 0,02 million tonnes	
Investment	Total investment is expected to be NOK 72,2 billion (2007 values) NOK 58,9 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

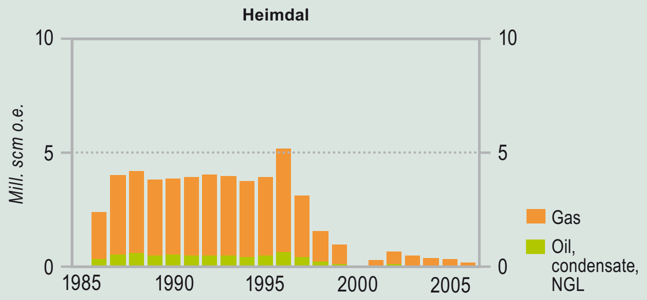
Development:
The Heidrun field is located on Haltenbanken in the Norwegian Sea. The sea depth in the area is 350 metres. The field has been developed with a floating concrete tension leg platform, installed over a subsea template with 56 well slots. The northern part of the field is developed with subsea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

Reservoir:
The reservoir consists of Lower and Middle Jurassic sandstones. The structure is heavily faulted.

Recovery strategy:
The recovery strategy for the field is pressure maintenance using water injection and injection of excess gas.

Transport:
Heidrun oil is transferred to tankers at the field and shipped to Mongstad and Tetney (UK). The gas is sent through Haltenpipe to Tjeldbergodden and in Åsgard Transport to Kårstø.

Status:
Continuous efforts are being made to find new methods to increase oil recovery and prove new deposits.



Heimdal

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	23,80 %
	Norsk Hydro Produksjon AS	19,44 %
	Petoro AS	20,00 %
	Statoil ASA	20,00 %
	Total E&P Norge AS	16,76 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	7,2 million scm oil	0,8 million scm oil
	42,7 billion scm gas	
Production	**Estimated production in 2007:**	
	Gas: 0,15 billion scm	
Investment	Total investment is expected to be NOK 19,5 billion (2007 values)	
	NOK 19,4 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

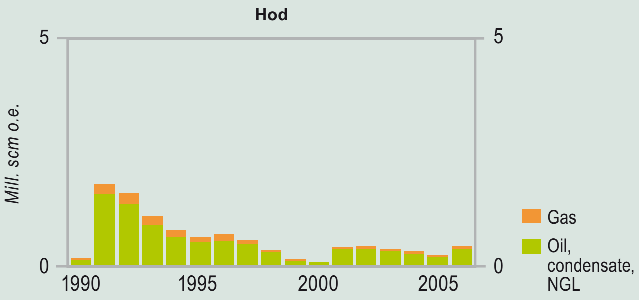
Development:
Heimdal is a gas field located in the northern part of the North Sea. The sea depth in the area is 120 metres. The field has been developed with an integrated drilling, production and accommodation facility with a steel base (HMP1). The Heimdal Jurassic development was approved on 02.10.1992. PDO for Heimdal Gas Centre (HGS) was approved on 15.01.1999. This included a new riser facility (HRP), bridge connected 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 Tertiary sandstones in the Heimdal formation deposited as deep-marine turbidity currents.

Recovery strategy:
Heimdal has been recovered with pressure depletion and the production is now marginal. When the facility has spare capacity, gas is produced from the Heimdal reservoir.

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 recourses that can be tied to Heimdal to extend the lifetime of the gas centre.



Hod

Block and production licence	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 31.12.2006**
	10,3 million scm oil	1,8 million scm oil
	1,8 billion scm gas	0,3 billion scm gas
	0,4 million tonnes NGL	0,2 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 5 000 barrels/day Gas: 0,06 billion scm, NGL: 0,01 million tonnes	
Investment	Total investment is expected to be NOK 2,6 billion (2007 values)	
	NOK 2,5 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

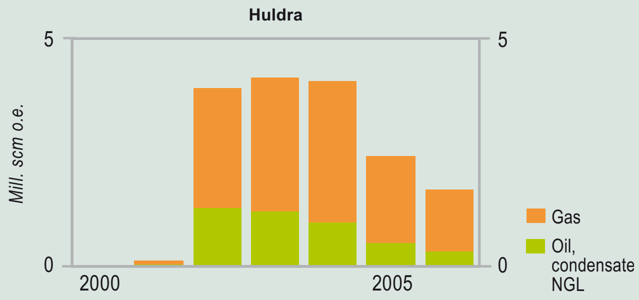
Development:
Hod is an oil field located 13 kilometres south of the Valhall field in the sourthern part of the North Sea. The sea depth is 72 metres. The field is developed with an unmanned production facility, which is remotely controlled from the Valhall field. The PDO for the Hod Sadel area was approved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

Reservoir:
The field produces from chalk in the Ekofisk, Tor and Hod formations. The field consists of the three structures Hod Vest, Hod Øst and Hod Sadel.

Recovery strategy:
Recovery takes place through pressure depletion. Since 2001, gas lift has been used in the main producer on the field to increase production. In 2006 a pilot for water injection was implemented to evaluate if this could be a strategy to increase the reserves from the field.

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. Several wells in the Sadel area have been drilled from a facility south on the Valhall field and increased the production from Hod. The pilot for water injection will continue in 2007.



Huldra

Block and production licence	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 ASA	
Licensees	Norske ConocoPhillips AS	23,34 %
	Petoro AS	31,96 %
	Statoil ASA	19,88 %
	Talisman Energy Norge AS	0,50 %
	Total E&P Norge AS	24,33 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	4,9 million scm oil	0,7 million scm oil
	15,7 billion scm gas	3,7 billion scm gas
	0,1 million tonnes NGL	
Production	**Estimated production in 2007:** Oil: 4 000 barrels/day Gas: 0,95 billion scm	
Investment	Total investment is expected to be NOK 8,2 billion (2007 values) NOK 8,0 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

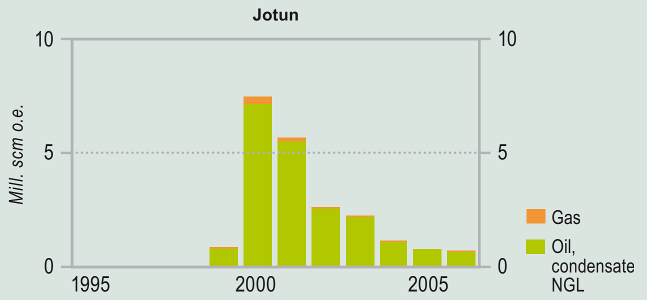
Development:
Huldra is a gas and condensate field located north of Oseberg in the northern part of the North Sea. The field is developed with a steel wellhead facility with a simple process plant. Gas and condensate are transported in separate pipelines. The facility is remotely operated from Veslefrikk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

Reservoir:
The Huldra reservoir is in a rotated fault block and consists of Jurassic sandstones in the Brent group. The reservoir has high pressure and high temperature and lies at a depth of 3500 – 3900 metres. Reservoir communication is uncertain, but the production history indicates two main segments without pressure communication. There are many small faults in the field.

Recovery strategy:
Huldra is recovered by pressure depletion. The field went off plateau in the autumn of 2004.

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:
A gas compressor was installed on Huldra in 20006 and became operational from January 2007. The compressor will increase the recovery at reduced wellhead pressure. A new well is planned in 2007 to prove resources in deeper layers which may extend the lifetime of the field.



Jotun

Block and production licence	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	Ener Petroleum ASA	45,00 %
	ExxonMobil Exploration & Production Norway AS	45,00 %
	Lundin Norway AS	7,00 %
	Petoro AS	3,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	24,6 million scm oil	3,7 million scm oil
	0,9 billion scm gas	0,1 billion scm gas
Production	**Estimated production in 2007:**	
	Oil: 12 000 barrels/day Gas: 0,04 billion scm	
Investment	Total investment is expected to be NOK 11,5 billion (2007 values)	
	NOK 11,4 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

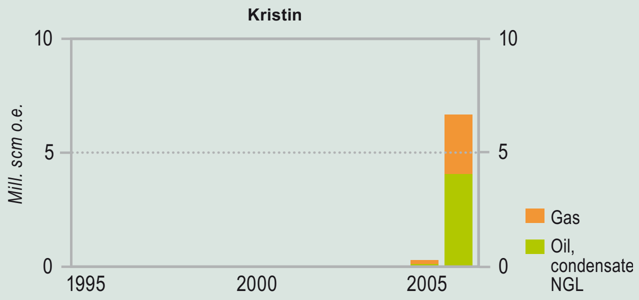
Development:
Jotun is an oil field located 25 kilometres north of Balder in the northern part of the North Sea. The sea depth in the area is 126 metres. The field has been developed with a combined accommodation, production and storage vessel, Jotun A, and a wellhead facility, Jotun B. Jotun is integrated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

Reservoir:
The Jotun field comprises three oil filled structures. The eastern structure also has a gas cap. The reservoirs were deposited in a submarine fan system. The three structures are relatively flat and only separated by minor depressions. 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 natural water influx combined with partial reinjection of produced water.

Transport:
The oil is exported via loading buoys to tankers. The processed rich gas is exported via Statpipe to Kårstø.

Status:
Two new production wells were drilled on Jotun late in 2006. Disappointing results from these have led to reduced reserves.



Kristin

Block and production licence	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 ASA	
Licensees	Eni Norge AS	8,25 %
	Mobil Development Norway AS	10,88 %
	Norsk Hydro Produksjon AS	14,00 %
	Petoro AS	19,58 %
	Statoil ASA	41,30 %
	Total E&P Norge AS	6,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	33,7 million scm oil	32,6 million scm oil
	31,1 billion scm gas	28,3 billion scm gas
	6,8 million tonnes NGL	6,2 million tonnes NGL
	2,1 million scm condensate	
Production	**Estimated production in 2007:** Oil: 96 000 barrels/day Gas: 4,43 billion scm, NGL: 1,03 million tonnes	
Investment	Total investment is expected to be NOK 25,4 billion (2007 values) NOK 21,4 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

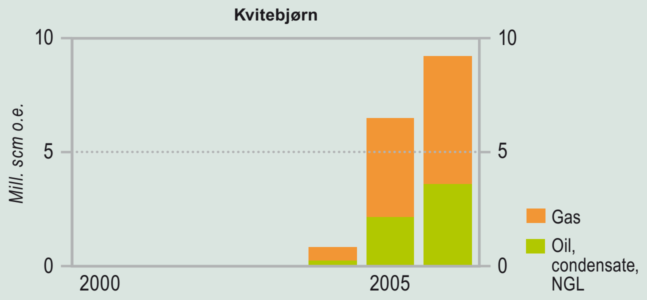
Development:
Kristin is a gas field in the Norwegian Sea. The field is developed with a subsea facility and a semi-submersible production facility for processing. The sea depth in the area is about 370 metres. Provision has been made for tie-in and processing of other deposits in the area when Kristin comes off plateau. Tyrihans is now being tied back to Kristin.

Reservoir:
The reservoirs are in Middle Jurassic sandstones at a depth of 4 600 metres. The reservoirs are in the Garn, Ile and Tofte formations and contain gas and condensate under very high pressure and with very high temperatures.

Recovery strategy:
Kristin is recovered by pressure depletion.

Transport:
The rich gas from Kristin is transported in a dedicated pipeline to Åsgard Transport and to Kårstø, where ethane and NGL are separated out. The sales gas is transported on to the Continent. Light oil is separated and stabilised on Kristin and transferred to Åsgard for storage and shipping. Condensate from Kristin is sold as oil (Halten Blend).

Status:
Drilling of production wells has taken longer than planned, and production so far is therefore lower than expected.



Kvitebjørn

Block and production licence	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 ASA	
Licensees	Enterprise Oil Norge AS	**6,45 %**
	Norsk Hydro Produksjon AS	15,00 %
	Petoro AS	30,00 %
	Statoil ASA	43,55 %
	Total E&P Norge AS	5,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	18,0 million scm oil	12,7 million scm oil
	51,9 billion scm gas	41,3 billion scm gas
	2,3 million tonnes NGL	1,3 million tonnes NGL
Production	Estimated production in 2007: Oil: 49 000 barrels/day Gas: 7,31 billion scm, NGL: 0,26 million tonnes	
Investment	Total investment is expected to be NOK 12,1 billion (2007 values) NOK 10,6 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Florø	

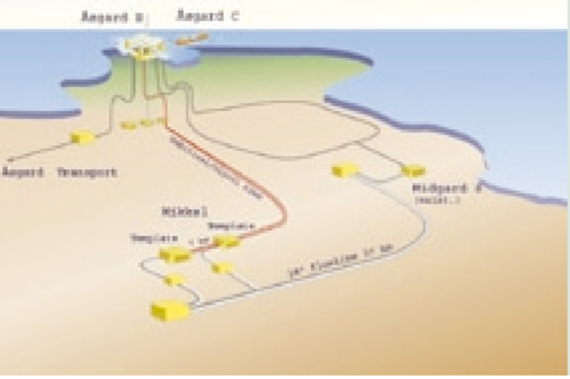
Development:
Kvitebjørn is a gas and condensate field located east in the Tampen area in the northern part of the North Sea. The field is developed with an integrated accommodation, drilling and processing facility with a steel jacket. Sea depth in the area is approximately 190 metres. 10 production wells have been drilled in the reservoir. Drill cuttings and produced water are injected in a dedicated disposal well. Revised PDO for Kvitebjørn was approved in December 2006.

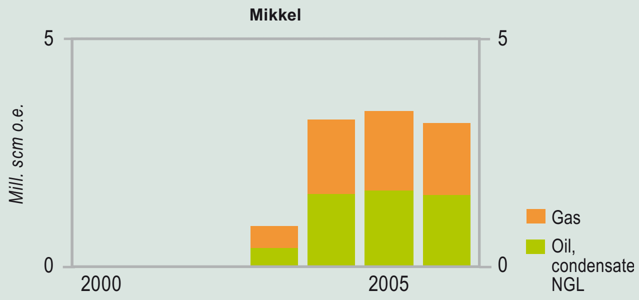
Reservoir:
The reservoir consists of sandstones in the Middle Jurassic Brent group. The reservoir lies at approximately 4 000 metres depth, and has high temperature and pressure.

Recovery strategy:
Recovery is driven 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:
The production from Kvitebjørn was temporarily reduced from December 2006. The reduction will improve the possibility for further drilling to obtain higher production at a later stage and increased recovery in total.





Mikkel

Block and production licence	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 ASA	
Licensees	Eni Norge AS	14,90 %
	Mobil Development Norway AS	33,48 %
	Norsk Hydro Produksjon AS	10,00 %
	Statoil ASA	33,97 %
	Total E&P Norge AS	7,65 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	4,6 million scm oil	4,4 million scm oil
	23,1 billion scm gas	17,7 billion scm gas
	4,6 million tonnes NGL	3,1 million tonnes NGL
	2,1 million scm condensate	
Production	**Estimated production in 2007:** Oil: 11 000 barrels/day Gas: 1,6 billion scm, NGL: 0,35 million tonnes	
Investment	Total investment is expected to be NOK 2,4 billion (2007 values) NOK 2,0 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stjørdal	
Main supply base	Kristiansund	

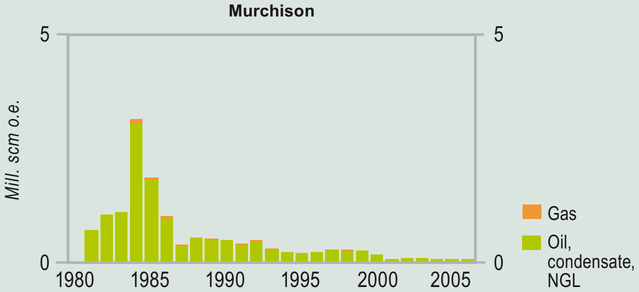
Development:
Mikkel is a gas and condensate field located east in the Norwegian Sea, about 30 kilometres north of Draugen. The sea depth in the area is 220 metres. The field has been developed with two subsea templates tied back to Åsgard B.

Reservoir:
The field has a 300 metres thick gas-condensate column and a thin underlying oil rim. The reservoir consists of Middle Jurassic sandstones in six structures separated by faults, all with good reservoir quality.

Recovery strategy:
Mikkel is produced by pressure depletion.

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

Status:
Additional wells will be considered after some years of production experience.



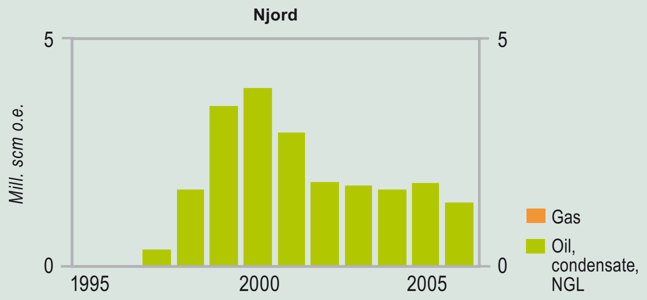
Murchison

Block and production licence	Block 33/9 - production licence 037 C, awarded 2000 Norwegian part of the field is 22,2%, British part is 77,8%	
Discovered	1975	
Development approval	15.12.1976	
On stream	28.09.1980	
Operator	CNR International (UK) Limited	
Licensees	Revus Energy ASA Statoil ASA CNR International (UK) Limited	10,68 % 11,52 % 77,80 %
Recoverable reserves (Norwegian part)	**Original:** 13,7 million scm oil 0,4 billion scm gas	**Remaining as of 31.12.2006** 0,3 million scm oil 0,1 billion scm gas
Production	Estimated production in 2007: Oil: 2 000 barrels/day	
Investment	Total investment is expected to be NOK 7,5 billion (2007 values) NOK 7,5 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Aberdeen, Skottland	
Main supply base	Peterhead, Skottland	

Development:
Murchison is straddling the boundary between the Norwegian and British sector 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 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.

Transport:
Both the Norwegian and British licensees' share of the oil and NGL is piped through the Brent system to Sullom Voe in the Shetlands.

Status:
Murchison is in tail production. A well drilled in 2006 towards the Norwegian sector did not provide basis for new production, but other possibilities are evaluated.



Njord

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	E.ON Ruhrgas Norge AS	30,00 %
	Endeavour Energy Norge AS	2,50 %
	Gaz de France Norge AS	20,00 %
	Mobil Development Norway AS	20,00 %
	Norsk Hydro Produksjon AS	20,00 %
	Petoro AS	7,50 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	24,0 million scm oil	24,0 million scm oil
	10,5 billion scm gas	10,5 billion scm gas
	1,4 million tonnes NGL	1,4 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 17 000 barrels/day Gas: 0,44 billion scm, NGL: 0,07 million tonnes	
Investment	Total investment is expected to be NOK 14,4 billion (2007 values) NOK 12,5 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Kristiansund	
Main supply base	Kristiansund	

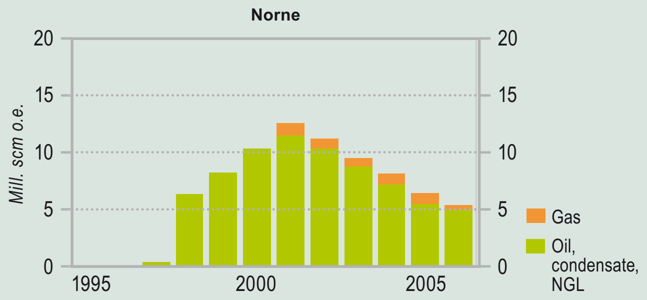
Development:
Njord is an oil field located around 30 kilometres west of Draugen in the Norwegian Sea. The sea depth in the area is 330 metres. The field has been developed with a steel semi-submersible drilling, accommodation and production facility and a storage vessel, Njord B. The facility is located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

Reservoir:
The reservoir consists of Jurassic sandstones in the Tilje and Ile formations. The field has a complicated fault pattern with only partial communication between the segments.

Recovery strategy:
Most of the gas produced at Njord is reinjected for pressure support and increased oil recovery from parts of the field. The western and northern segments produce with pressure depletion.

Transport:
The oil is offloaded from the storage vessel to tankers for transport to the market.

Status:
Two new production wells have been drilled on Njord in 2006. Gas export from the field is scheduled to begin in October 2007.



Norne

Block and production licence	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 ASA	
Licensees	Eni Norge AS	6,90 %
	Norsk Hydro Produksjon AS	8,10 %
	Petoro AS	54,00 %
	Statoil ASA	31,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	90,0 million scm oil	17,3 million scm oil
	10,7 billion scm gas	5,7 billion scm gas
	1,2 million tonnes NGL	0,7 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 64 000 barrels/day Gas: 0,54 billion scm, NGL: 0,07 million tonnes	
Investment	Total investment is expected to be NOK 24,5 billion (2007 values) NOK 20,1 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Harstad	
Main supply base	Sandnessjøen	

Development:
Norne is an oil field located around 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, connected to six subsea wellhead templates. Flexible risers carry the wellstream up to the vessel. 6507/3-1 Alve will be tied to Norne for processing and transport.

Reservoir:
The Norne reservoir is in Jurassic sandstones. Oil is mainly found in the Ile and Tofte formations, and gas in the Garn formation. The reservoir is found at a depth of 2500 metres below sea level.

Recovery strategy:
The oil is produced with water injection as drive mechanism. Gas injection ceased in 2005 and all gas was planned to be exported. In order to avoid rapid pressure depletion in the gas cap, gas will be injected for an extended period of time.

Transport:
The oil is loaded to tankers for shipping. Gas is transported through a dedicated pipeline to Åsgard and on through the Åsgard Transport pipeline to Kårstø.

Status:
Various measures to increase recovery have been implemented on Norne, including use of new well technology. A multi-branch well will be drilled in 2007. Several discoveries and prospects in the area are considered to be tied back to Norne, 6507/3-1 Alve, among others. Efforts are being made to extend the lifetime of the field.

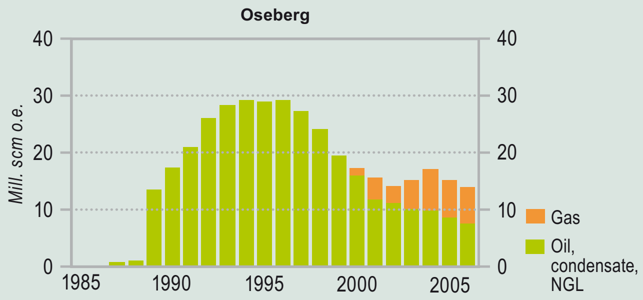
 

Oseberg

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4,70 %
	Norsk Hydro Produksjon AS	34,00 %
	Norske ConocoPhillips AS	2,40 %
	Petoro AS	33,60 %
	Statoil ASA	15,30 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	353,7 million scm oil	19,0 million scm oil
	108,6 billion scm gas	92,6 billion scm gas
	7,4 million tonnes NGL	3,2 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 89 000 barrels/day Gas: 2,89 billion scm, NGL: 0,58 million tonnes	
Investment	Total investment is expected to be NOK 91,9 billion (2007 values) NOK 82,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Oseberg is an oilfield with a gas cap. The field is located in the northern part of the North Sea. The sea depth in the area is 100 metres. Oseberg is developed in multiple phases. The 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. The Oseberg C facility, an integrated production, drilling and accommodation facility (PDQ), lies 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. The facilities at the field centre process oil and gas from the Oseberg Øst, Oseberg Sør and Tune fields. 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.

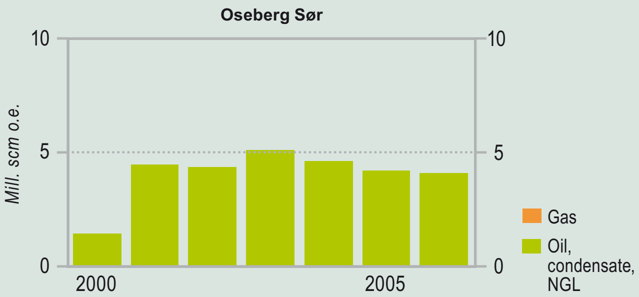
Reservoir:
The field consists of several sandstone reservoirs in the Middle Jurassic Brent group, and is divided into several structures. The main reservoir is located in the Oseberg and Tarbert formations, but production also takes place from the Etive and Ness formations. The field has generally good reservoir characteristics.



Recovery strategy:
The Oseberg field produces through pressure maintenance with the injection of both gas and water, and with WAG (water alternating gas) injection. Massive upflank gas injection has provided extremely good oil displacement, and a large gas cap has now developed that will be recovered in the future. Formerly, injection gas was imported from Troll Øst (TOGI) and Oseberg Vest.

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

Status:
The challenge on Oseberg will be to produce the oil that remains under the gas cap, and to balance the gas and oil production from the field. There are plans to start test production from an overlying chalk reservoir on the Oseberg field during 2007. Oseberg Delta will commence production in 2008.



Oseberg Sør

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4,70 %
	Norsk Hydro Produksjon AS	34,00 %
	Norske ConocoPhillips AS	2,40 %
	Petoro AS	33,60 %
	Statoil ASA	15,30 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	49,2 million scm oil	21,1 million scm oil
	11,0 billion scm gas	6,7 billion scm gas
Production	**Estimated production in 2007:** Oil: 54 000 barrels/day Gas: 0,77 billion scm	
Investment	Total investment is expected to be NOK 19,5 billion (2007 values) NOK 16,7 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

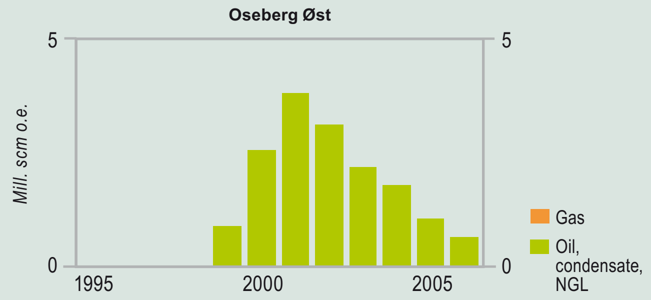
Development:
Oseberg Sør is an oil field located south of Oseberg in the northern part of the North Sea. The sea depth in the area is approximately 100 metres. The field has been developed with an integrated steel facility with accommodation, drilling module and first stage separation of oil and gas. Additional 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. An amended PDO for the Oseberg Sør J deposit was approved on 15.05.2003.

Reservoir:
Oseberg Sør consists of ten deposits with Jurassic sandstone reservoirs in separate structures.

Recovery strategy:
Recovery mainly takes place using water injection, but there is also WAG (water alternating gas) injection in parts of the field.

Transport:
The oil is transported by pipeline to the Oseberg Field Centre. Following final processing, the oil is routed to the Sture terminal whereas gas is transported via Oseberg Gas Transport into Statpipe via the Heimdal facility.

Status:
Several small deposits in the area are being evaluated for tie-in to the Oseberg Sør facility.



Oseberg Øst

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4,70 %
	Norsk Hydro Produksjon AS	34,00 %
	Norske ConocoPhillips AS	2,40 %
	Petoro AS	33,60 %
	Statoil ASA	15,30 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	27,8 million scm oil	11,7 million scm oil
	0,4 billion scm gas	0,2 billion scm gas
Production	**Estimated production in 2007:**	
	Oil: 10 000 barrels/day Gas: 0,02 billion scm	
Investment	Total investment is expected to be NOK 10,2 billion (2007 values)	
	NOK 8,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

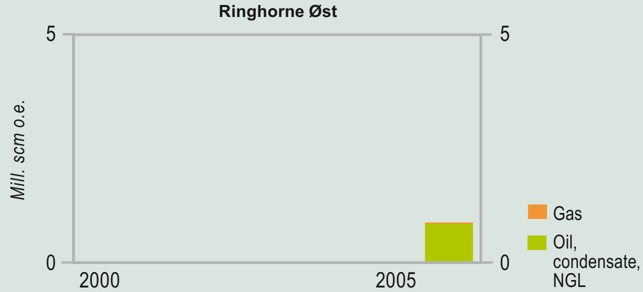
Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:
The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

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:
Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be set on stream in February 2008.



Ringhorne Øst

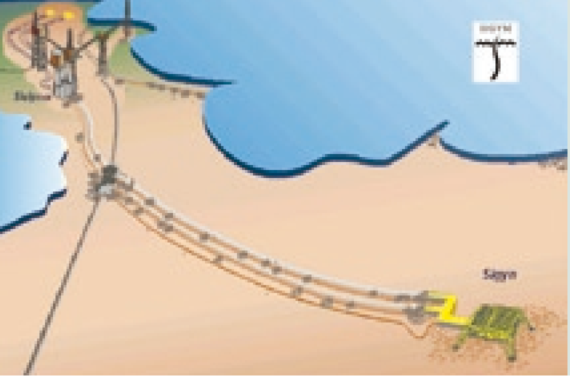
Block and production licence	Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 169, awarded 1991	
Discovered	2003	
Development approval	25.11.2005 by the King in Council	
On stream	19.03.2006	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	77,38 %
	Norsk Hydro Produksjon AS	11,70 %
	Petoro AS	7,80 %
	Statoil ASA	3,12 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	5,8 million scm oil	4,8 million scm oil
	0,2 billion scm gas	0,2 billion scm gas
Production	**Estimated production in 2007:**	
	Oil: 19 000 barrels/day Gas: 0,06 billion scm	
Investment	Total investment is expected to be NOK 1,0 billion (2007 values) NOK 0,6 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	

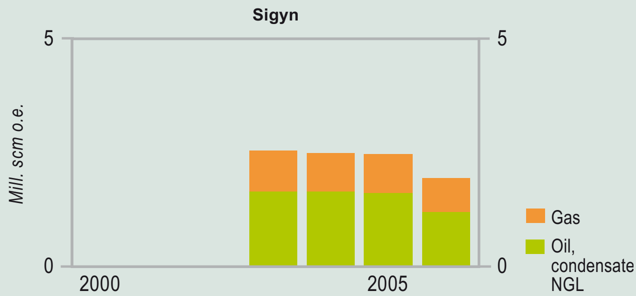
Development:
Ringhorne Øst is located north of Balder in the northern part of the North Sea. The sea depth in the area is approximately 130 meters. The field is developed by three production wells drilled from the Ringhorne facility.

Reservoir:
The reservoir contains oil with associated gas corresponding to the Jurassic reservoir in the Ringhorne deposit.

Recovery strategy:
The plan is to recover the field with natural water influx as drive mechanism. Two water injection wells may be drilled if more pressure support is needed.

Transport:
The production from Ringhorne Øst is transported to the Balder vessel for processing and export.





Sigyn

Block and production licence	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 %
	Norsk Hydro Produksjon AS	10,00 %
	Statoil ASA	50,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	6,6 billion scm gas	3,3 billion scm gas
	3,0 million tonnes NGL	1,7 million tonnes NGL
	5,6 million scm condensate	1,8 million scm condensate
Production	**Estimated production in 2007:**	
	Gas: 0,71 billion scm, NGL: 0,27 million tonnes, Condensate: 0,50 million scm	
Investment	Total investment is expected to be NOK 2,3 billion (2007 values)	
	NOK 2,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

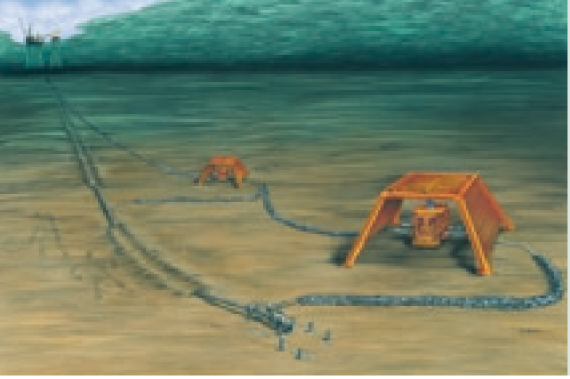
Development:
Sigyn is located in the Sleipner area in the southern part of the North Sea. The sea depth in the area is around 70 metres. The field has been developed with a subsea template as a satellite of Sleipner Øst. The wellstream is controlled from Sleipner Øst and is sent through two pipelines to the Sleipner A facility.

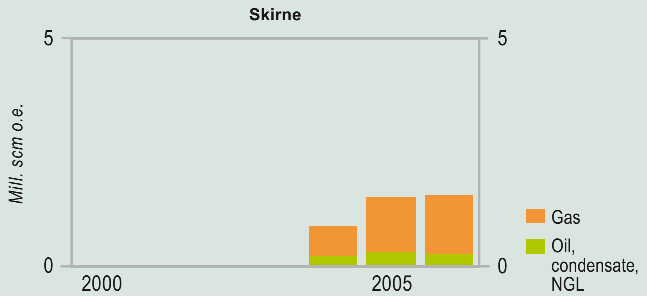
Reservoir:
The field consists of the Sigyn Vest deposits, which contain gas/condensate, and Sigyn Øst, which contains light oil. The main reservoir is located in the Triassic Skagerrak formation.

Recovery strategy:
The field is produced with pressure depletion as the drive mechanism.

Transport:
The gas is exported using the dry gas system at Sleipner A. Condensate is transported via the condensate pipeline from Sleipner A to Kårstø.

Status
The project, Sleipner Super Low Pressure, was initiated in June 2006 and has boosted production from the Sigyn Vest deposit. The production from the Sigyn Øst deposit has been rerouted to the third stage separator on Sleipner. This results in an increased production from the Sigyn Øst deposit.





Skirne

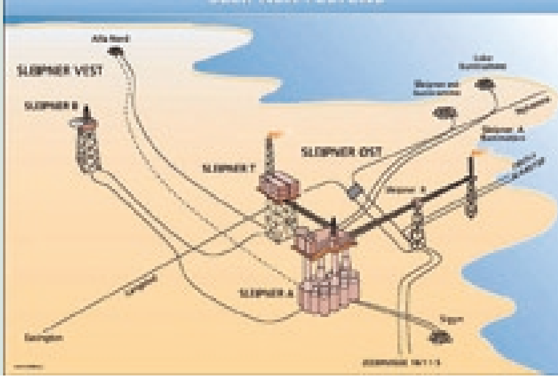
Block and production licence	Blokk 25/5 - production licence 102, awarded 1985
Discovered	1990
Development approval	05.07.2002 by the Crown Prince Regent in Council
On stream	03.03.2004
Operator	Total E&P Norge AS
Licensees	Marathon Petroleum Norge AS 20,00 %
	Norsk Hydro Produksjon AS 10,00 %
	Petoro AS 30,00 %
	Total E&P Norge AS 40,00 %
Recoverable reserves	**Original:** — **Remaining as of 31.12.2006**
	2,1 million scm oil — 1,3 million scm oil
	8,8 billion scm gas — 5,7 billion scm gas
Production	**Estimated production in 2007:**
	Oil: 5 000 barrels/day Gas: 1,17 billion scm
Investment	Total investment is expected to be NOK 2,5 billion (2007 values)
	NOK 2,4 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Stavanger

Development:
Skirne, also including the Byggve deposit, contains gas and condensate and is situated east of Heimdal in the northern part of the North Sea. The sea depth in the area is 120 metres. The field is developed with two subsea wellheads tied to Heimdal by pipeline.

Reservoir:
The reservoir consists of sandstone in the Middle Jurassic Brent Group.

Recovery strategy:
The recovery mechanism is pressure depletion.

Transport:
The wellstream from Skirne is transported in pipeline to the Heimdal facility for processing. Gas is exported in Vesterled or Statpipe, whereas condensate is transported to Brae in the UK sector.



Sleipner Vest

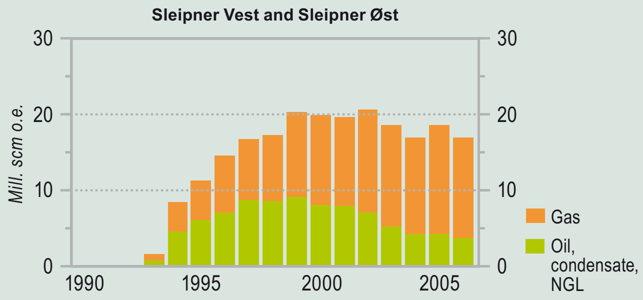
Block and production licence	Block 15/6 - production licence 029, awarded 1969	
	Block 15/9 - production licence 046, awarded 1976	
Discovered	1974	
Development approval	14.12.1992 by the Storting	
On stream	29.08.1996	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	32,24 %
	Norsk Hydro Produksjon AS	8,85 %
	Statoil ASA	49,50 %
	Total E&P Norge AS	9,41 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006***
	117,8 billion scm gas	50,1 billion scm gas
	8,1 million tonnes NGL	3,9 million tonnes NGL
	29,6 million scm condensate	3,5 million scm condensate
Production	**Estimated production in 2007:**	
	Gas: 9,65 billion scm, NGL: 0,46 million tonnes, Condensate: 1,53 million scm	
Investment	Total investment is expected to be NOK 26,8 billion (2007 values)	
	NOK 23,7 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

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

Development:
Sleipner Vest is a gas field in the southern part of the North Sea. The sea depth in the area is 110 metres. The field is developed with a wellhead facility, Sleipner B, which is remotely operated from Sleipner A on the Sleipner Øst field, and a processing facility, Sleipner T, which is bridge connected 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. Most of the reserves are found in the Hugin formation, which consists of a sequence of beach deposits. The underlying Sleipner formation has fluvial deposits. The faults in the field are generally not sealing, and communication between the geological sand accumulations is generally good.

Recovery strategy:
Sleipner Vest production is driven by pressure depletion.



Sleipner Vest includes total production from Sleipner Øst and Sleipner Vest

Transport:
Gas and condensate from Sleipner Vest are processed at Sleipner T, where CO_2 is also removed from the gas. Processed gas from Sleipner Vest goes to Sleipner A for further export. CO_2 is injected into the Utsira formation via a dedicated injection well from Sleipner A. Unstable condensate from Sleipner Vest and Sleipner Øst is combined at Sleipner A and sent to Kårstø for processing to stable condensate and NGL products.

Status:
To maintain production when the field comes off plateau in 2007, it was decided in 2006 to install a new compressor on Sleipner B, planned to be in operation from October 2008. Drilling and development of several nearby deposits is also being evaluated for the coming years, and a drilling rig will be installed on Sleipner B in 2008.

Sleipner Øst

Block and production licence	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 ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30,40 %
	Norsk Hydro Produksjon AS	10,00 %
	Statoil ASA	49,60 %
	Total E&P Norge AS	10,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006***
	68,1 billion scm gas	50,1 billion scm gas
	13,1 million tonnes NGL	3,9 million tonnes NGL
	27,9 million scm condensate	3,5 million scm condensate
Production	**Estimated production in 2007:**	
	Gas: 2,70 billion scm, NGL: 0,38 million tonnes, Condensate: 0,66 million scm	
Investment	Total investment is expected to be NOK 39,6 billion (2007 values)	
	NOK 36,1 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Dusavik	

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

Development:
Sleipner Øst is a gas and condensate field in the southern 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 jacket, Sleipner A. A separate riser facility has also been built, Sleipner R, which is bridge connected to Sleipner A. Sleipner R also connects Sleipner A to the pipelines for gas transport, two subsea templates and the flare stack Sleipner F. A subsea template has been installed for production from the northern part of Sleipner Øst and one for production at Loke. Three Sigyn wells are also 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 on 19.06.1998.

Reservoir:
The Sleipner Øst and Loke resources are mainly found in sandstones in the Ty formation from the Tertiary age and sandstones in the Hugin formations from the Middle Jurassic age. There is no pressure communication between the two reservoir zones. The Hugin formation consists of shallow marine deposits and coastal, land-deposited sediments. The Ty reservoir consists of shallow marine fan deposits. The underlying Triassic Skagerrak formation makes up the main reservoir at Loke and consists of alluvial deposits with moderate to poor reservoir characteristics.

Recovery strategy:
The Hugin reservoir produces with pressure depletion. The Ty reservoir has been produced by dry gas recycling until October 2005. To optimise production, the wells are now produced with a reduced inlet pressure in separator B. Sleipner Øst went off plateau in December 2005, but “super low pressure” production, which started in June 2006 will maintain the production level for a longer period of time.

Transport:
The wellstream from Sleipner Øst is processed on Sleipner A together with the production from Gungne and Sigyn. Unstable condensate from Sleipner Vest and Sleipner Øst is mixed and sent to Kårstø for processing into stable condensate and NGL products. Processed gas is mixed with gas from Troll and exported via Draupner to Zeebrugge. Starting in 2007, gas from Ormen Lange will be exported through the Langeled pipeline from Nyhamna via Sleipner A to the United Kingdom.

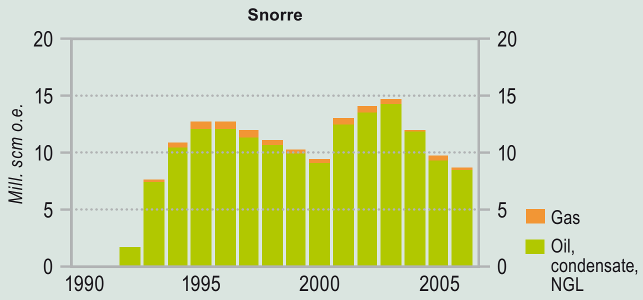
Status:
No new wells were drilled on Sleipner Øst in 2006. However there are plans for drilling activity in 2007.

Snorre

Block and production licence	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 ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	11,58 %
	Hess Norge AS	1,04 %
	Idemitsu Petroleum Norge AS	9,60 %
	Norsk Hydro Produksjon AS	17,77 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	8,28 %
	Statoil ASA	15,55 %
	Total E&P Norge AS	6,18 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	234,0 million scm oil	87,4 million scm oil
	6,5 billion scm gas	0,9 billion scm gas
	4,6 million tonnes NGL	0,3 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 140 000 barrels/day	
Investment	Total investment is expected to be NOK 90,8 billion (2007 values)	
	NOK 64,8 billion have been invested as of 31.12.2006 (2007 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 meters. Snorre A in the south is a floating steel facility (TLP) for accommodation, drilling and processing. Snorre A has also a separate process module for production from the Vigdis field. A subsea template with ten well slots, Snorre UPA, is located centrally in 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 steel facility. Amended PDO for Snorre, including a processing module for Vigdis on Snorre A, 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, slightly tilted fault blocks. The reservoir sandstones belong to the Lower Jurassic and Triassic Statfjord and Lunde formations, and have been deposited on flood plains. The reservoir has a complex structure with many channels and internal flow barriers.



Recovery strategy:
Snorre is produced with pressure maintenance by water injection, gas injection and WAG (water alternating gas) injection. Foam assisted injection (FAWAG) has also been used in parts of the reservoir.

Transport:
Oil and gas are separated in two stages on 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 reinjected into the reservoir, but can, when required, also be sent by pipeline to Snorre A.

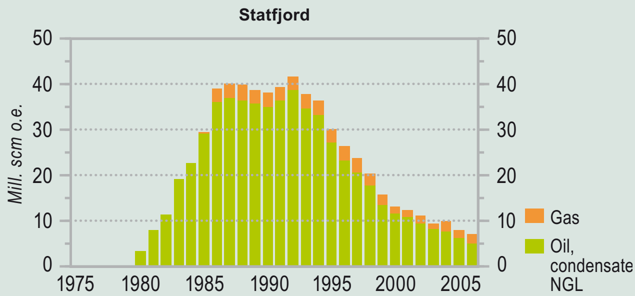
Status:
Snorre has considerable remaining resources in the field. In 2007 it is expected decisions to increase the capacities for production and injection of water and gas. Several measures are being evaluated to increase recovery on Snorre.

Statfjord

Block and production licence	Block 33/12 - production licence 037, awarded 1973 Block 33/9 - production licence 037, awarded 1973 Norwegian part of the field is 85,47%, British part is 14,53%	
Discovered	1974	
Development approval	16.06.1976 by the Storting	
On stream	24.11.1979	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	8,55 %
	Enterprise Oil Norge AS	0,89 %
	ExxonMobil Exploration & Production Norway AS	21,37 %
	Norske ConocoPhillips AS	10,33 %
	Statoil ASA	44,34 %
	BP Petroleum Development Ltd	4,84 %
	Centrica Resources Limited	4,84 %
	ConocoPhillips (U.K.) Limited.	4,84 %
Recoverable reserves (Norwegian part)	**Original:** 565,0 million scm oil 79,4 billion scm gas 25,6 million tonnes NGL	**Remaining as of 31.12.2006** 13,6 million scm oil 25,7 billion scm gas 11,4 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 68 000 barrels/day Gas: 1,6 billion scm, NGL: 0,71 million tonnes	
Investment	Total investment is expected to be NOK 127,9 billion (2007 values) NOK 117,3 billion have been invested as of 31.12.2006 (2007 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 in the northern part of the North Sea. 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 on 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.

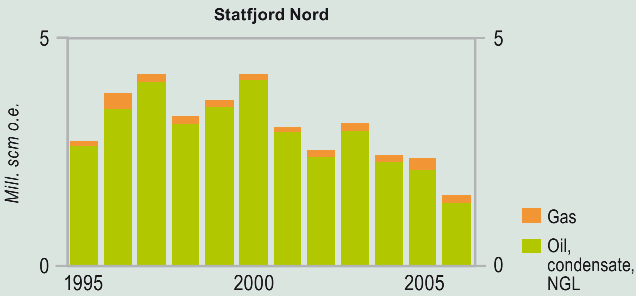
Reservoir:
The Statfjord field consists of one large fault block, tilted towards the west, as well as a number of smaller fault compartments along the east flank. The reservoirs consist of sandstones belonging to the Brent group, the Cook formation and the Statfjord formation.



Recovery strategy:
The Brent reservoir produces with pressure support from WAG (water alternating gas) injection. The Statfjord formation produces with pressure support from upflank water injection and supplemental gas injection, and WAG injection in the lower flank. The oil in the Cook formation is recovered by phasing in wells penetrating the reservoir, or by deepening existing wells. Statfjord Late Life will entail that all injection will cease in in the near future and the injection wells will be converted to water producers.

Transport:
Stabilised oil is stored in storage cells at each facility. Oil is loaded to tankers from one of the three oil loading systems at the field. The gas is sent through Statpipe to Kårstø, where NGL is separated before dry gas is transported on to Emden. The UK licencees route their share of the gas through the FLAGS (Far North Liquids and Gas System) pipeline from Statfjord B to St. Fergus in Scotland. Tampen Link is a new pipeline for export of the gas from Statfjord Late Life to the UK via FLAGS.

Status:
The plan for pressure blowdown of the reservoirs in the Statfjord field (Statfjord Late Life) will extend the lifetime of the field by at least 10 years and provide extra recovery of gas and oil. The work with modification of the facilities started in 2006. It was also decided in 2006 to optimise the project by delaying the pressure depletion of the Brent reservoir with one year, from 2007 to 2008. The lifetime of Statfjord A and the Snorre tie to Statfjord A are now being evaluated in cooperation with the licensees in the Snorre field.



Statfjord Nord

Block and production licence	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 ASA

Licensees	A/S Norske Shell	10,00 %
	Enterprise Oil Norge AS	1,04 %
	ExxonMobil Exploration & Production Norway AS	25,00 %
	Norske ConocoPhillips AS	12,08 %
	Petoro AS	30,00 %
	Statoil ASA	21,88 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	42,1 million scm oil	8,6 million scm oil
	2,7 billion scm gas	0,6 billion scm gas
	0,9 million tonnes NGL	0,2 million tonnes NGL

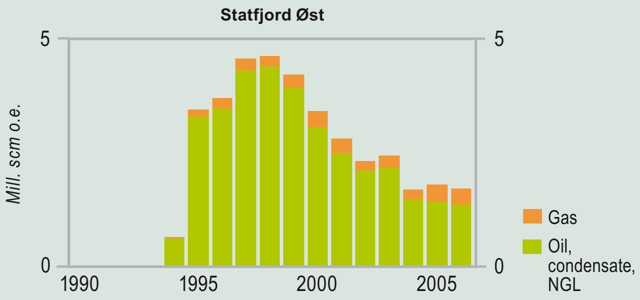
Production	**Estimated production in 2007:**
	Oil:17 000 barrels/day Gas: 0,08 billion scm, NGL: 0,03 million tonnes
Investment	Total investment is expected to be NOK 8,4 billion (2007 values) NOK 7,7 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Stavanger
Main supply base	Sotra

Development:
Statfjord Nord is an oil field located approximately 17 kilometres north of Statfjord in the Tampen area in the northern part of the North Sea. 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 templates are for production and one is for water injection. One well slot is used for an injection well at the Sygna field.

Reservoir:
The Statfjord Nord reservoir consists of Middle Jurassic sandstones belonging to the Brent group, and Upper Jurassic sandstones of the Munin formation.

Recovery strategy:
The field produces with pressure support from water injection. It is being studied whether water alternating gas (WAG) is a feasible method for increased oil recovery on Statfjord Nord.

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.



Statfjord Øst

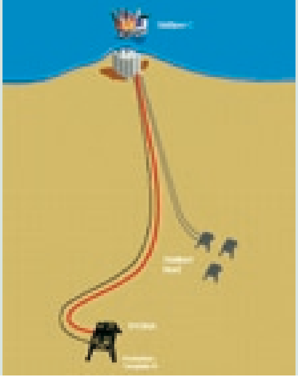
Block and production licence	Block 33/9 - production licence 037, awarded 1973 Block 34/7 - production licence 089, awarded 1984	
Discovered	1976	
Development approval	11.12.1990 by the Storting	
On stream	24.09.1994	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	5,00 %
	Enterprise Oil Norge AS	0,52 %
	ExxonMobil Exploration & Production Norway AS	17,75 %
	Idemitsu Petroleum Norge AS	4,80 %
	Norsk Hydro Produksjon AS	6,64 %
	Norske ConocoPhillips AS	6,04 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	1,40 %
	Statoil ASA	25,05 %
	Total E&P Norge AS	2,80 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	37,4 million scm oil	5,5 million scm oil
	4,1 billion scm gas	0,9 billion scm gas
	1,5 million tonnes NGL	0,3 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 22 000 barrels/day Gas: 0,28 billion scm, NGL: 0,11 million tonnes	
Investment	Total investment is expected to be NOK 7,8 billion (2007 values) NOK 6,9 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Sotra	

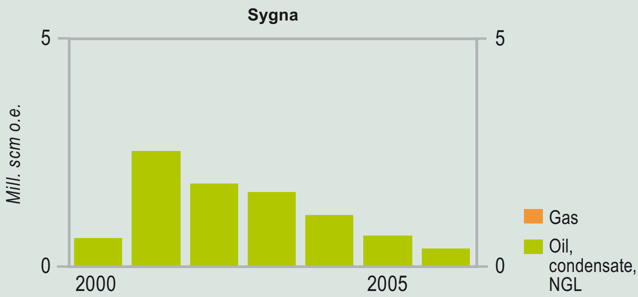
Development:
Statfjord Øst is an oil field located approximately 7 kilometres northeast of the Statfjord field in the Tampen area in the northern part of the North Sea. The sea depth in the area is 150-190 metres. The field has been developed with three subsea templates tied back to Statfjord C. Two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

Reservoir:
The Statfjord Øst reservoir consists of Middle Jurassic sandstones in the upper and lower parts of the Brent group.

Recovery strategy:
The field is produced with pressure support from water injection. When blowdown of the Statfjord field commences, pressure will also decrease in Statfjord Øst. In 2006 a long-reach production well was drilled from Statfjord C to accelerate recovery as a counter measure to this. It is being evaluated to implement Through Tubing Rotary Drilling (TTRD) as a method to increase oil recovery from Statfjord Øst. Gas lift in the production wells may also be initiated.

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





Sygna

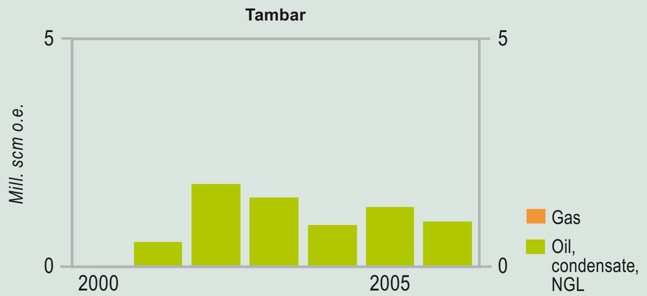
Block and production licence	Block 33/9 - production licence 037, awarded 1973 Block 34/7 - production licence 089, awarded 1984	
Discovered	1996	
Development approval	30.04.1999 by the King in Council	
On stream	01.08.2000	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	5,50 %
	Enterprise Oil Norge AS	0,57 %
	ExxonMobil Exploration & Production Norway AS	18,48 %
	Idemitsu Petroleum Norge AS	4,32 %
	Norsk Hydro Produksjon AS	5,98 %
	Norske ConocoPhillips AS	6,65 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	1,26 %
	Statoil ASA	24,73 %
	Total E&P Norge AS	2,52 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	12,7 million scm oil	3,8 million scm oil
Production	**Estimated production in 2007:** Oil: 7 000 barrels/day	
Investment	Total investment is expected to be NOK 2,7 billion (2007 values) NOK 2,3 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Florø	

Development:
The Sygna oil field is situated just north of the Statfjord Nord field in the Tampen area in the northern part of the North Sea. The sea depth in the area is 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 Brent group sandstones.

Recovery strategy:
The field is produced using water injection from Statfjord Nord.

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



Tambar

Block and production licence	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 DONG E&P Norge AS	55,00 % 45,00 %
Recoverable reserves	**Original:** 8,6 million scm oil 2,7 billion scm gas 0,2 million tonnes NGL	**Remaining as of 31.12.2006** 1,8 million scm oil 2,7 billion scm gas
Production	**Estimated production in 2007:** Oil: 14 000 barrels/day Gas: 0,21 billion scm	
Investment	Total investment is expected to be NOK 2,3 billion (2007 values) NOK 1,9 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

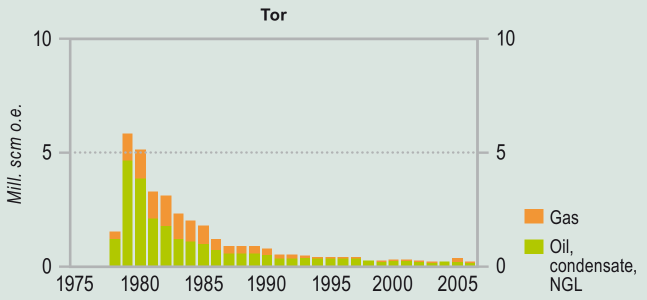
Development:
Tambar is an oilfield located southeast of the Ula field in the southern part of the North Sea. The sea depth in the area is 68 metres. The field has been developed with an unmanned wellhead facility.

Reservoir:
The reservoir consists of Upper Jurassic sandstones deposited in a shallow marine environment. The reservoir quality varies, and the reservoir is divided into zones according to the quality of the sand.

Recovery strategy:
Three wells produce with pressure depletion as drive mechanism.

Transport:
Production is transported to Ula through the Ula Gyda Interconnector Pipeline (UGIP) for processing. UGIP is an interim solution until a new pipeline is in place by 1 September 2007. Oil is exported in the existing pipeline system to Teesside via Ekofisk. The gas is used for gas injection on Ula.

Status:
A multiphase pump to increase oil recovery from Tambar is being installed. Planned start-up is 4th quarter of 2007. A study is being conducted to evaluate the potential for water injection and new wells, possibly from 2009.



Tor

Block and production licence	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 %
	Norsk Hydro Produksjon AS	5,81 %
	Petoro AS	3,69 %
	Statoil ASA	0,83 %
	Total E&P Norge AS	48,20 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	23,9 million scm oil	1,6 million scm oil
	11,0 billion scm gas	0,3 billion scm gas
	1,2 million tonnes NGL	
Production	**Estimated production in 2007:** Oil: 3 000 barrels/day Gas: 0,04 billion scm	
Investment	Total investment is expected to be NOK 9,1 billion (2007 values) NOK 8,9 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

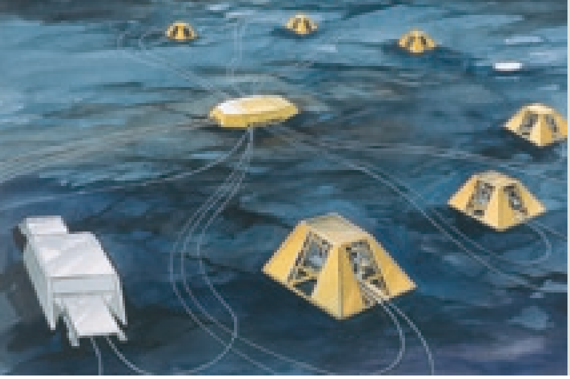
Development:
Tor is an oil field in the Ekofisk area in the southern part of the North Sea. The field has been developed with a combined wellhead and processing facility. The Tor field development was approved as part of the Ekofisk development. The sea depth in the area is 70 metres.

Reservoir:
The main reservoir at Tor is at a depth of around 3 200 metres and consists of fractured chalk belonging to the Tor formation. The Ekofisk formation also contains oil, but has lower reservoir quality.

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.

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

Status:
A study is currently evaluating the future of Tor. A new production well was drilled in 2006 as part of this work. This resulted in a doubling of the production from Tor.

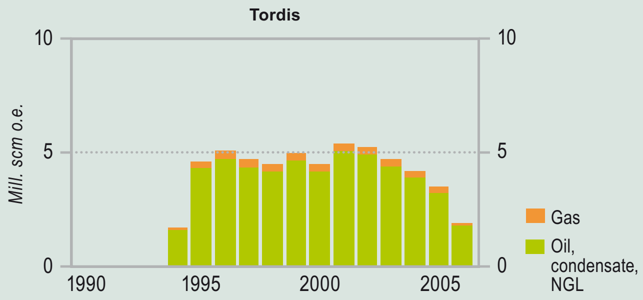


Tordis

Block and production licence	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 ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10,50 %
	Idemitsu Petroleum Norge AS	9,60 %
	Norsk Hydro Produksjon AS	13,28 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	2,80 %
	Statoil ASA	28,22 %
	Total E&P Norge AS	5,60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	64,5 million scm oil	15,9 million scm oil
	5,6 billion scm gas	1,9 billion scm gas
	1,8 million tonnes NGL	0,5 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 46 000 barrels/day Gas: 0,20 billion scm, NGL: 0,08 million tonnes	
Investment	Total investment is expected to be NOK 11,8 billion (2007 values)	
	NOK 10,6 billion have been invested as of 31.12.2006 (2007 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 subsea manifold. The wellstream is transferred to Gullfaks C through two pipelines. Injection water is piped to Tordis from Gullfaks C. Tordis consists of four discoveries: 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 in the Brent group. The reservoir in Borg consists of Upper Jurassic sandstones, and the reservoir in 34/7-25 S consists of sandstones from the Brent group and sandstones equivalent to Upper Jurassic. The Tordis reservoirs lie at a depth of 2 000 – 2 500 metres.



Recovery strategy:
Production from Tordis is partially accomplished with pressure maintenance by water injection and aquifer drive. Pressure at Borg is fully maintained using water injection. Recovery at Tordis Øst takes place with pressure support from aquifer drive. Tordis IOR entails improved oil recovery through low pressure production.

Transport:
Oil from Tordis is transported to Gullfaks C for processing and exported by tankers. The export gas is sent through Statpipe to Kårstø.

Status:
A new production well was drilled in 2006. Tordis IOR includes new wells, a subsea facility for separation and injection of produced water, and modifications on Gullfaks C for low pressure production. The subsea separator will be installed on the field in 2007.

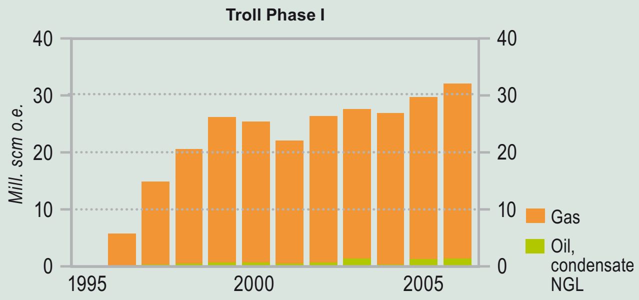
Troll

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 comprises two main structures: Troll Øst and Troll Vest, and roughly two-thirds of the recoverable gas reserves lie in Troll Øst. A thin oil rim 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 to 27 metres. 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 3. 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

Block and production licence	Block 31/2 - production licence 054. Awarded 1979	
	Block 31/3 - production licence 085. Awarded 1983	
	Block 31/3 - production licence 085C. 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 085C. Awarded 2002	
Discovered	1983	
Development approval	15.12.1986 by the Storting	
On stream	09.02.1996	
Operator	Statoil ASA	
Licensees	A/S Norske Shell	8,10 %
	Norsk Hydro Produksjon AS	9,78 %
	Norske ConocoPhillips AS	1,62 %
	Petoro AS	56,00 %
	Statoil ASA	20,80 %
	Total E&P Norge AS	3,69 %
Recoverable reserves*	**Original:**	**Remaining as of 31.12.2006**
	1332,1 billion scm gas	1061,9 billion scm gas
	25,7 million tonnes NGL	23,8 million tonnes NGL
	1,6 million scm condensate	
Production	**Estimated production in 2007:**	
	Gas: 30,00 billion scm, NGL: 0,64 million tonnes	
Investment	Total investment is expected to be NOK 76,3 billion (2007 values)	
	NOK 55,1 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Ågotnes	

** Reserves include TOGI gas*



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

Reservoir:
The reservoirs in Troll Øst and Troll Vest are mainly shallow marine Upper Jurassic sandstones in the Sognefjord formation. Part of the reservoir is also belonging to the underlying Middle Jurassic Fensfjord formation. The field consists of three relatively large rotated fault blocks. The fault block to the east constitutes Troll Øst. Pressure communication between Troll Øst and Troll Vest has been proven. The oil column in Troll Øst is from 0-4 metres thick.

Recovery strategy:
The gas in Troll Øst is recovered by pressure depletion.

Transport:
The gas from Troll Øst and Troll Vest is transported through two multiphase 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:
Studies are being conducted by the licensees to evaluate increased export capacity for gas based on acceleration of gas recovery from Troll Øst.

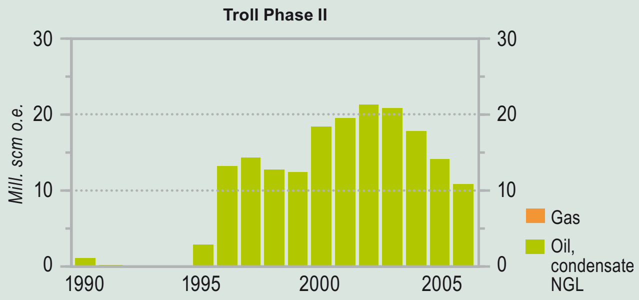
 

Troll II

Block and production licence	Block 31/2 - production licence 054. Awarded 1979	
	Block 31/3 - production licence 085. Awarded 1983	
	Block 31/3 - production licence 085C. 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 085C. Awarded 2002	
Discovered	1979	
Development approval	18.05.1992 by the Storting	
On stream	19.09.1995	
Operator	Norsk Hydro Produksjon AS	
Licensees	A/S Norske Shell	8,10 %
	Norsk Hydro Produksjon AS	9,78 %
	Norske ConocoPhillips AS	1,62 %
	Petoro AS	56,00 %
	Statoil ASA	20,80 %
	Total E&P Norge AS	3,69 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	231,7 million scm oil	50,6 million scm oil
Production	**Estimated production in 2007:**	
	Oil: 162 000 barrels/day	
Investment	Total investment is expected to be NOK 80,7 billion (2007 values)	
	NOK 71,2 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Mongstad	

Development:
Troll Phase II has been developed with Troll B, a floating accommodation and process facility with concrete hull, and Troll C, a semi-submersible accommodation and process facility with steel hull. Oil from Troll Vest is produced from 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 plant that separates produced water from the wellstream on the sea floor and reinjects water into the ground, before sending oil up to the platform. The Troll C processing facility is also used for production from the Fram field. Development of Troll C was approved in 1997. There have been several PDO approvals concerning subsea templates at Troll Vest.

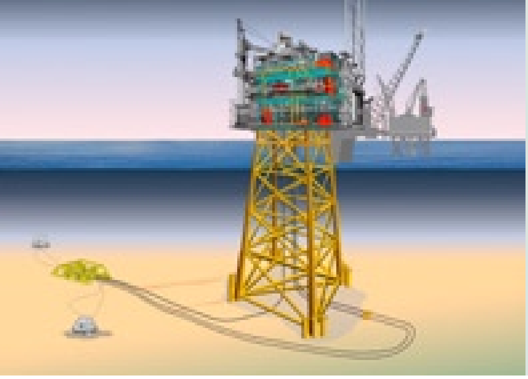
Reservoir:
The gas and oil is found mainly in the Sognefjord formation, which consists of shallow marine sandstones of Upper Jurassic age. Part of the reservoir is also in the underlying Fensfjord formation. The field consists of three relatively large rotated fault blocks. The oil in the Troll Vest province is formed as a 22-26 metre thick oil column under a small gas cap. In the Troll Vest gas province there is an oil column of around 12-14 metres and a gas column of up to 200 metres. There is a significant volume of residual oil below the oil column in Troll Vest. A small oil discovery was made in 2005 in the Brent Group, which lies deeper than the oil in the main reservoir.

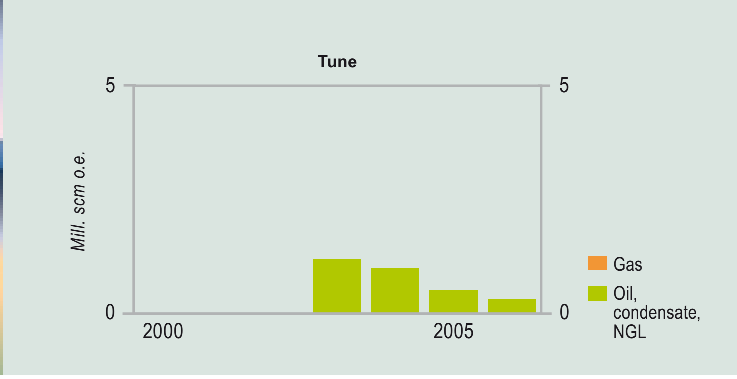


Recovery strategy:
Oil production at Troll Vest takes place through long horizontal wells drilled right above the oil/water contact in the thin oil zone. The main recovery strategy is pressure depletion, but there will be simultaneous expansion of the gas cap above and the water zone below the oil. In the Troll Vest oil province, some of the gas produced has been injected back into the reservoir to optimise the oil production. One important aspect of the strategy is to recover the oil quickly, because less oil can be extracted when the pressure declines in Troll Øst. For this reason, limits have also been placed on gas extraction from Troll Øst.

Transport:
Gas from Troll Øst and Troll Vest is transported through two multiphase pipelines to the gas processing plant at Kollsnes. Condensate is separated from the gas and transported on by pipeline, partly to the Sture terminal, partly to Mongstad. The dry gas is sent 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 up to three mobile drilling facilities in activity. In total, more than 100 oil production wells have now been drilled at Troll Vest. Over the last few years, decisions have been made each year in favour of drilling new production wells that contribute to increasing oil reserves from Troll, and there are still a number of wells in the drilling plan. Several multi-branch wells have been drilled, with up to six branches in one well. The licensees are evaluating new measures to maintain oil production.





Tune

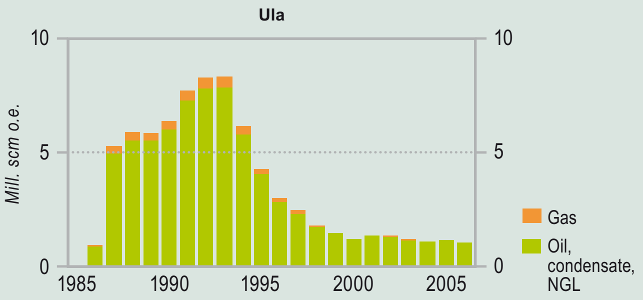
Block and production licence	Block 30/5 - production licence 034, awarded 1969 Block 30/6 - production licence 053, awarded 1979 Block 30/8 - production licence 190, awarded 1993
Discovered	1996
Development approval	17.12.1999 by the King in Council
On stream	28.11.2002
Operator	Norsk Hydro Produksjon AS
Licensees	Norsk Hydro Produksjon AS 40,00 % Petoro AS 40,00 % Statoil ASA 10,00 % Total E&P Norge AS 10,00 %
Recoverable reserves	**Original:** 3,2 million scm oil; 15,6 billion scm gas; 0,1 million tonnes NGL **Remaining as of 31.12.2006** 0,2 million scm oil; 3,2 billion scm gas
Production	**Estimated production in 2007:** Oil: 3 000 barrels/day Gas: 1,82 billion scm
Investment	Total investment is expected to be NOK 4,9 billion (2007 values) NOK 4,4 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Bergen
Main supply base	Mongstad

Development:
The Tune field is a gas and gas condensate field located around 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 with four production wells in the centre of the field. 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). There are prospects in the area which may be tied to the Tune template.

Reservoir:
The reservoir consists of Middle Jurassic sandstones and is divided into several inclined fault blocks.

Recovery strategy:
Recovery is driven by pressure depletion. Low pressure production will increase recovery from the field.

Transport:
The Tune subsea facility is connected to the Oseberg D facility by two flow lines. An inlet module for Tune production is installed at Oseberg D. Condensate from Tune is stabilised at the Oseberg Field Centre and transported to the Sture terminal through the Oseberg Transport System (OTS). Gas from Tune is injected into the Oseberg field, while the field's licensees receive sales gas from the Oseberg field.



Ula

Block and production licence	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 DONG E&P Norge AS Svenska Petroleum Exploration AS	80,00 % 5,00 % 15,00 %
Recoverable reserves	**Original:** 80,0 million scm oil 3,8 billion scm gas 3,1 million tonnes NGL	**Remaining as of 31.12.2006** 12,3 million scm oil 0,6 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 16 000 barrels/day NGL: 0,03 million tonnes	
Investment	Total investment is expected to be NOK 22,1 billion (2007 values) NOK 21,0 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

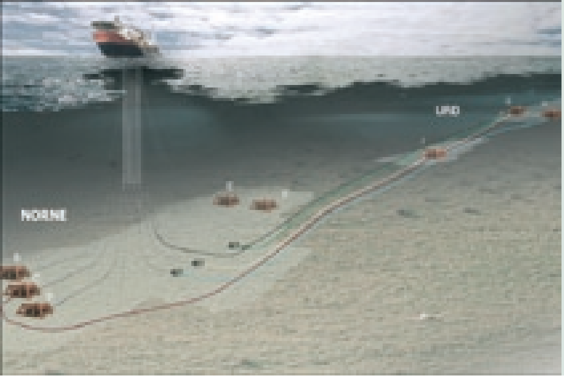
Development:
Ula is an oilfield in the southern part of the North Sea. The sea depth in the area is 70 metres. The development consists of three conventional steel facilities for production, drilling and accommodation. The facilities are connected by bridges.

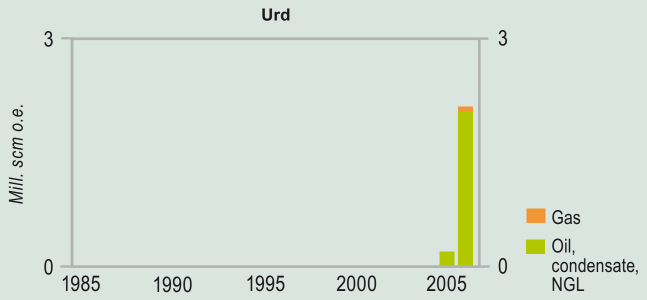
Reservoir:
The main reservoir is in Upper Jurassic sandstones. The sand was deposited in a shallow marine environment. Permeability varies from good to very good, but deteriorates towards the flanks.

Recovery strategy:
Initially, oil was recovered by pressure depletion, but after some years water injection was implemented to increase recovery. WAG (water/alternating gas injection) started in 1998. As access to gas increased by processing production from Tambar at Ula, the WAG programme has been extended.

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

Status:
The Blane field is being tied back to the Ula field for processing. Gas from Blane will be used for injection in Ula. At the same time, Ula gas capacity is being upgraded. Based on the positive effect on oil recovery, evaluation is ongoing to expand the WAG program by drilling additional wells and importing more gas for injection.





Urd

Block and production licence	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 ASA	
Licensees	Eni Norge AS	11,50 %
	Norsk Hydro Produksjon AS	13,50 %
	Petoro AS	24,55 %
	Statoil ASA	50,45 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	10,5 million scm oil	8,3 million scm oil
	0,1 billion scm gas	
Production	**Estimated production in 2007:**	
	Oil: 29 000 barrels/day	
Investment	Total investment is expected to be NOK 5,0 billion (2007 values)	
	NOK 4,0 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Harstad	

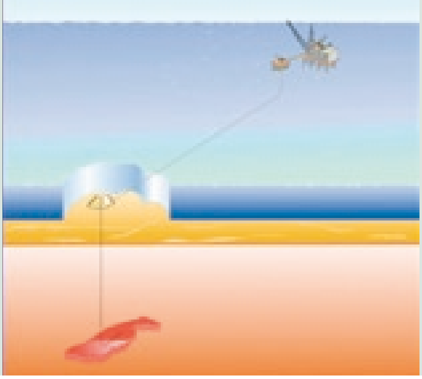
Development:
Urd is located northeast of Norne in the Norwegian Sea. The sea depth in the area is approximately 380 metres. The field encompasses three oil filled structures in the 6608/10-6 Svale, 6608/10-8 Stær and 6608/10-9 Lerke discoveries. Urd has been developed with subsea templates tied back to the Norne vessel. The field has eight development wells; three producers and two water injectors in the Svale deposit and two producers and one water injector in the Stær deposit.. The well templates have available slots for additional wells or phase-in of additional resources.

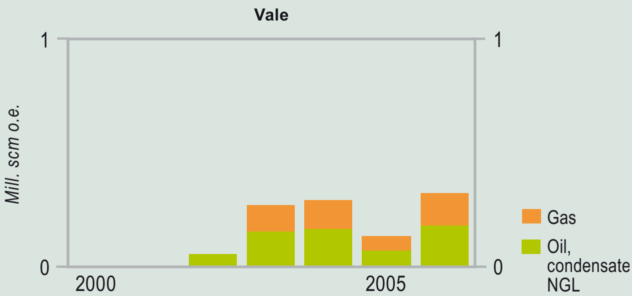
Reservoir:
The deposits lie in rotated fault blocks in the northern part of the Dønna Terrace. The reservoir is from the Lower to Middle Jurassic ages, and consists of sandstone in the Åre, Tilje and Ile formations.

Recovery strategy:
The oil in the Svale deposit is heavy, viscous and under-saturated, while the oil in the Stær deposit is lighter and more like the oil in Norne. Both reservoirs have lower gas-oil ratio than Norne. Svale and Stær are drained using water injection. The wells are also equipped with gas lift to handle low pressure and high water cut.

Transport:
The wellstream is processed on the Norne vessel, and oil/condensate are stabilised and offloaded together with oil or condensate from the Norne field. The rich gas is exported together with gas from the Norne field in Åsgard Transport for treatment at Kårstø.

Status:
The last planned well was completed in August 2006. Urd has been developed according to the original plan, with regard to cost and time frame.





Vale

Block and production licence	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	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	46,90 %
	Norsk Hydro Produksjon AS	28,85 %
	Total E&P Norge AS	24,24 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	1,7 million scm oil	1,1 million scm oil
	2,2 billion scm gas	1,7 billion scm gas
Production	**Estimated production in 2007:**	
	Oil: 3 000 barrels/day Gas: 0,20 billion scm	
Investment	Total investment is expected to be NOK 2,4 billion (2007 values)	
	NOK 2,2 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	

Development:
Vale is located 16 kilometres north of Heimdal in the northern part of the North Sea. The field has been developed with a subsea well tied back to Heimdal. Water depths in the area are approximately 115 metres.

Reservoir:
The reservoir consists of Middle Jurassic sandstone in the Brent group.

Recovery strategy:
Recovery is driven by pressure depletion.

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

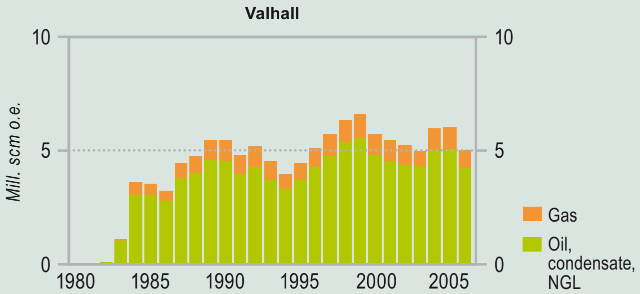
Valhall

Block and production licence	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 Enterprise Oil Norge AS Hess Norge AS Total E&P Norge AS	28,09 % 28,09 % 28,09 % 15,72 %
Recoverable reserves	**Original:** 143,1 million scm oil 25,8 billion scm gas 5,1 million tonnes NGL	**Remaining as of 31.12.2006** 50,4 million scm oil 7,4 billion scm gas 2,2 million tonnes NGL
Production	**Estimated production in 2007:** Oil: 65 000 barrels/day Gas: 0,73 billion scm, NGL: 0,08 million tonnes	
Investment	Total investment is expected to be NOK 65,4 billion (2007 values) NOK 47,6 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Stavanger	
Main supply base	Tananger	

Development:
Valhall is an oilfield located in the southern part of the North Sea. The sea depth in the area is 70 metres. The field was originally developed with three facilities, for accommodation, drilling and production. In 1996, a riser 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 in 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 wells. 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.

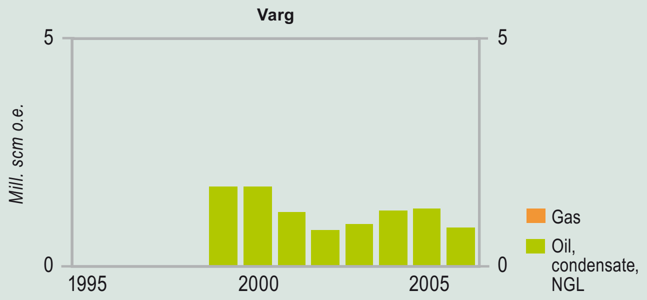
Reservoir:
The Valhall field produces from chalk in the Tor and Hod formations from the Upper Cretaceous age. The chalk in the Tor formation is fine-grained and soft, with pervasive fractures that allow oil and water to flow more easily. As a result of pressure depletion from production, the chalk has compacted, causing subsidence of the seabed at Valhall.

Recovery strategy:
Recovery originally took place by pressure depletion with compaction drive. Water injection in the centre of the field started in January 2004.



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:
Production from Valhall is expected to remain stable, but with great uncertainty regarding the number of new wells and the effect of water injection. In relation to current planning, there are significant possibilities for further increases in reserves by using all well slots and optimising water injection. As the seabed has subsided, and the original facilities have aged, the licensees are planning a new facility with processing plant and accommodation. A decision has been made to supply electric power to this facility from land. A PDO is expected in 2007.



Varg

Block and production licence	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	Pertra ASA 5,00 %
	Petoro AS 30,00 %
	Talisman Energy Norge AS 65,00 %
Recoverable reserves	**Original:** 15,1 million scm oil
	Remaining as of 31.12.2006 5,4 million scm oil
Production	**Estimated production in 2007:** Oil: 14 000 barrels/day
Investment	Total investment is expected to be NOK 7,2 billion (2007 values) NOK 7,1 billion have been invested as of 31.12.2006 (2007 values)
Operating organisation	Trondheim
Main supply base	Tananger

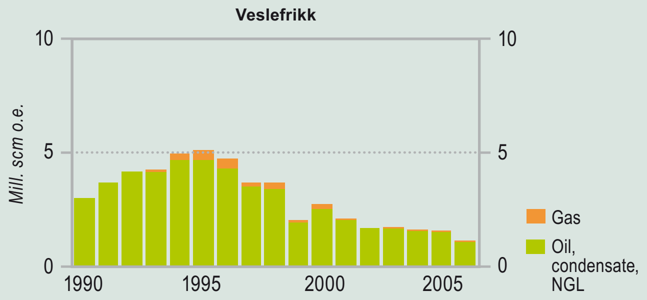
Development:
Varg is an oilfield to the south of Sleipner Øst in the southern part of the North Sea. The sea depth in the area is 84 metres. The field has been developed with a production vessel (Petrojarl Varg) with integrated oil storage, and a connected wellhead facility (Varg A). The decommissioning plan for the field was approved in 2001, and the plan was to produce until the summer of 2002.

Reservoir:
The field contains oil in Upper Jurassic sandstone reservoirs. The structure is segmented by faults and includes several isolated substructures.

Recovery strategy:
Recovery currently takes place by means of water and gas injection. In addition, gas lift is installed in most wells in 2006. The smaller structures are produced by pressure depletion.

Transport:
Oil is offloaded from the production vessel onto tankers.

Status:
Production from the Varg Vest segment, which started in 2004, has been instrumental in extending the life of the Varg field. Two new wells were drilled in 2006. The production in 2006 was below expectations, partly due to water breakthrough in production wells. Several discoveries and prospects are evaluated to be tied-in to Varg.



Veslefrikk

Block and production licence	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 ASA	
Licensees	Petoro AS	37,00 %
	RWE Dea Norge AS	13,50 %
	Revus Energy ASA	4,50 %
	Statoil ASA	18,00 %
	Talisman Energy Norge AS	27,00 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	56,2 million scm oil	8,4 million scm oil
	2,8 billion scm gas	0,6 billion scm gas
	1,1 million tonnes NGL	
Production	**Estimated production in 2007:**	
	Oil: 19 000 barrels/day	
Investment	Total investment is expected to be NOK 20,3 billion (2007 values)	
	NOK 17,8 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Sotra and Florø	

Development:
Veslefrikk is an oil field located 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 a drilling rig and 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 main reservoir consists of Jurassic sandstones in the Brent group, and is an uplifted fault block (horst). There are also reservoirs in the Intra Dunlin Sand and in the Statfjord formation.

Recovery strategy:
Production takes place with pressure support from water injection, and from 1997 water alternating gas (WAG) injection in parts of the field.

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

Status:
Production from Veslefrikk is in the decline phase. A project has been initiated to extend the lifetime of Veslefrikk. Several measures to increase the oil recovery are being evaluated. Prospects in the area will also be considered drilled and tied back to Veslefrikk.

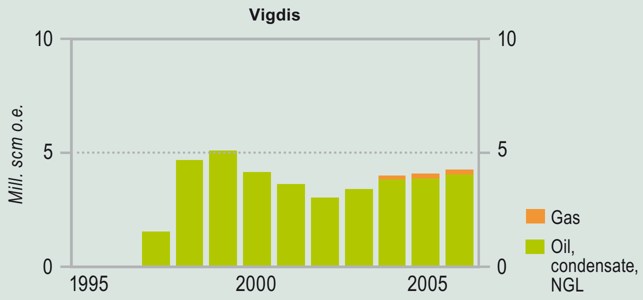
Vigdis

Block and production licence	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 ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	10,50 %
	Idemitsu Petroleum Norge AS	9,60 %
	Norsk Hydro Produksjon AS	13,28 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	2,80 %
	Statoil ASA	28,22 %
	Total E&P Norge AS	5,60 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	57,0 million scm oil	20,3 million scm oil
	1,8 billion scm gas	1,1 billion scm gas
	1,0 million tonnes NGL	0,6 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 67 000 barrels/day Gas: 0,26 billion scm, NGL: 0,14 million tonnes	
Investment	Total investment is expected to be NOK 13,0 billion (2007 values)	
	NOK 11,8 billion have been invested as of 31.12.2006 (2007 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 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.

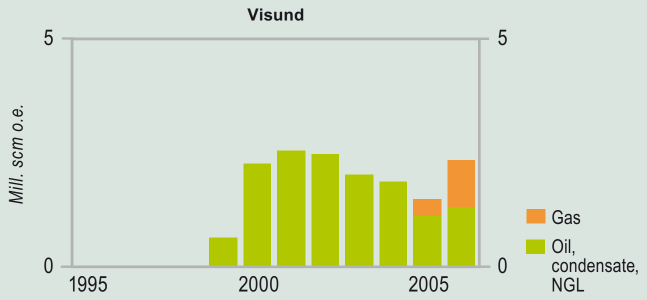
Reservoir:
The reservoirs consist of Middle Jurassic sandstones in the Brent group. The field also contains reservoirs that consist of Lower Jurassic and Upper Triassic sandstones in the Statfjord formation and sandstone reservoirs equivalent in time to the Upper Jurassic Draupne formation. The reservoirs are at a depth of 2 200 - 2 600 metres.

Recovery strategy:
Production is based on partial pressure maintenance using water injection. Parts of the Vigdis reservoir will be affected by the pressure blowdown of the Statfjord field, and therefore a new water injection well will be drilled. There are plans for increased water injection with water from Statfjord C.



Transport:
Stabilised oil from Vigdis is sent from the Vigdis module on Snorre A to Gullfaks A for storage and export. Gas from Vigdis is used for injection at Snorre.

Status:
A well was drilled and set on stream on the M5 deposit in 2006. A new subsea template was installed on the Vigdis Øst deposit in 2006, and two new wells for production and water injection will be drilled in 2007.



Visund

Block and production licence	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 ASA	
Licensees	Norsk Hydro Produksjon AS	20,30 %
	Norske ConocoPhillips AS	9,10 %
	Petoro AS	30,00 %
	Statoil ASA	32,90 %
	Total E&P Norge AS	7,70 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	27,8 million scm oil	13,7 million scm oil
	49,6 billion scm gas	48,2 billion scm gas
	6,4 million tonnes NGL	6,3 million tonnes NGL
Production	**Estimated production in 2007:**	
	Oil: 32 000 barrels/day Gas: 1,49 billion scm, NGL: 0,23 million tonnes	
Investment	Total investment is expected to be NOK 25,3 billion (2007 values)	
	NOK 19,6 billion have been invested as of 31.12.2006 (2007 values)	
Operating organisation	Bergen	
Main supply base	Florø	

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

Reservoir:
Visund contains oil and gas in several tilted fault blocks with separate pressure and liquid systems. The reservoirs are in Jurassic and Triassic sandstones in the Brent group and the Statfjord Formation.

Recovery strategy:
Oil production is driven by gas injection and water alternating gas injection (WAG). Produced water is also reinjected into one of the reservoirs. Limited gas export started in 2005.

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

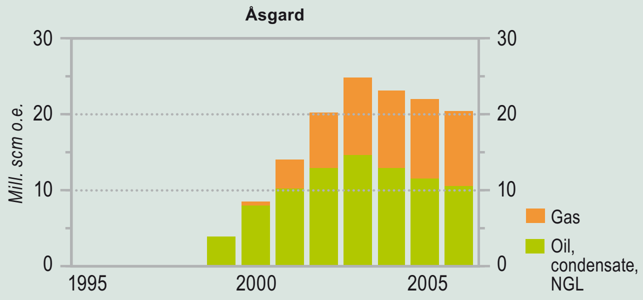
Status:
The challenge for Visund in the future is to maintain reservoir pressure to optimise oil recovery before gas export levels increase. One measure being evaluated is to access more water to increase water injection.


Åsgard

Block and production licence	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 ASA	
Licensees	Eni Norge AS	14,82 %
	Mobil Development Norway AS	7,24 %
	Norsk Hydro Produksjon AS	9,61 %
	Petoro AS	35,69 %
	Statoil ASA	24,96 %
	Total E&P Norge AS	7,68 %
Recoverable reserves	**Original:**	**Remaining as of 31.12.2006**
	99,5 million scm oil	49,1 million scm oil
	178,3 billion scm gas	126,0 billion scm gas
	34,7 million tonnes NGL	25,7 million tonnes NGL
	16,0 million scm condensate	
Production	**Estimated production in 2007:**	
	Oil: 128 000 barrels/day Gas: 10,27 billion scm, NGL: 2,22 million tonnes	
Investment	Total investment is expected to be NOK 68,0 billion (2007 values)	
	NOK 61,6 billion have been invested as of 31.12.2006 (2007 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. The field has been developed with subsea completed wells linked to a production and storage vessel, Åsgard A, 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 is processed. 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. Åsgard includes the discoveries 6506/12-1 Smørbukk, 6506/12-3 Smørbukk Sør and 6507/11-1 Midgard.

Reservoir:
6506/12-1 Smørbukk 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 from the Jurassic age and contain gas, condensate and oil. The reservoir is located at depths down to 4 850 metres. 6506/12-3 Smørbukk Sør, with reservoir rocks in the Garn, Ile and Tilje formations, is from the Lower to Middle Jurassic ages and contains oil, gas and condensate. The Midgard discovery is divided into four structural segments with the main reservoir in the Middle Jurassic Garn and Ile formations.



Recovery strategy:
The Smørbukk and Smørbukk Sør deposits are produced with gas injection. The Midgard deposit is produced by pressure depletion. There is a thin oil zone (11.5 m) below the gas cap in Midgard, but at the time there are no plans to produce the oil. Studies are ongoing to maintain an optimal flow in the pipeline from Midgard to Åsgard to ensure that a stable supply of low CO_2 gas from Midgard and Mikkel can be blended with high CO_2 gas from Kristin in Åsgard transport to Kårstø.

Transport:
Oil and condensate are temporarily stored at the field and shipped to shore by tankers. The gas is exported through Åsgard Transport to Kårstø. Starting on 01.07.2006, condensate from Åsgard will be 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.

Fields where production has ceased

The fields in this summary are shut down as of 31 December 2006. Plans for new development are however in progress for some of these fields.

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 Storting White Paper No. 47 (1999–2000)
On stream	26.05.1979
Production ceased	26.08.1998
Total production over field lifetime	Oil: 7,4 million scm. Gas: 15,6 billion scm. NGL: 1,0 million tonnes.

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2007/ 2008.

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 Storting White Paper No. 47 (1999–2000)
On stream	26.12.1977
Production ceased	05.08.1998
Total production over field lifetime	Oil: 2,9 million scm. Gas: 7,3 billion scm. NGL: 0,5 million tonnes.

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2007.

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 Storting White Paper No. 47 (1999–2000)
On stream	02.12.1979
Production ceased	05.08.1998
Total production over field lifetime	Oil: 4,8 million scm. Gas: 2,0 billion scm. NGL: 0,2 million tonnes.

Status: There are no specific plans to recover the remaining resources. Final disposal is planned for 2006 and in 2013.

Frigg

Block	25/1
Development approval	13.06.1974
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 26 September 2003 and White Paper No. 38 (2003–2004)
On stream	13.09.1977
Production ceased	26.10.2004
Total production over field lifetime	Gas: 116,2 billion scm. Condensate: 0,5 million scm.

Status: Final disposal of the facilities is ongoing.

Frøy

Block	25/2 and 25/5
Development approval	18.05.1992
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 29 May 2001 and in Storting White Paper No. 47 (1999–2000)
On stream	15.05.1995
Production ceased	05.03.2001
Total production over field lifetime	Oil: 5,6 million scm. Gas: 1,6 billion scm. Condensate: 0,1 million scm.

Status: No activity.

Lille-Frigg

Block	25/2
Development approval	06.09.1991
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999–2000) and in Storting White Paper No. 47 (1999–2000)
On stream	13.05.1994
Production ceased	25.03.1999
Total production over field lifetime	Oil: 1,3 million scm. Gas: 2,2 billion scm. NGL: 0,0 million tonnes.

Status: No activity.

Mime

Block	7/11
Development approval	06.11.1992
Cessation plan/ decommissioning	Storting Proposition No. 15 (1996–1997) and in Storting White Paper No. 47 (1999–2000)
On stream	01.01.2003
Production ceased	04.11.1993
Total production over field lifetime	Oil: 0,4 million scm. Gas: 0,1 billion scm. NGL: 0,0 million tonnes.

Status: Recovery of remaining resources is being evaluated. The plan calls for drilling an appraisal well in 2007.

Nordøst Frigg

Block	25/1 and 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
Total production over field lifetime	Gas: 11,6 billion scm. NGL: 0,0 million tonnes. Condensate: 0,1 million scm.

Status: No activity.

Odin

Block	30/10
Development approval	18.07.1980
Cessation plan/ decommissioning	Storting Proposition No. 50 (1995–1996) and in Storting White Paper No. 47 (1999–2000)
On stream	01.04.1984
Production ceased	01.08.1994
Total production over field lifetime	Gas: 27,3 billion scm. Condensate: 0,2 million scm.

Status: No activity.

Tommeliten Gamma

Block	1/9
Development approval	12.06.1986
Cessation plan/ decommissioning	Storting Proposition No. 53 (1999-2000) and in Storting White Paper No. 47 (1999–2000)
On stream	03.10.1988
Production ceased	05.08.1998
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 Storting White Paper No. 47 (1999–2000)
On stream	31.05.1977
Production ceased	25.08.1998
Total production over field lifetime	Oil: 12,2 million scm. Gas: 26,0 billion scm. NGL: 1,4 million tonnes.

Status: There are specific plans to recover the remaining resources by means of a new subsea development tied back to Ekofisk.

Yme

Block	9/2 and 9/5
Development approval	06.01.1995
Cessation plan/ decommissioning	The cessation plan was approved by Royal Decree 4 May 2001
On stream	27.02.1996
Production ceased	17.04.2001
Total production over field lifetime	Oil: 7,9 million scm.

Status: The new licensees in production licence 316 with Talisman as operator, have decided to recover remaining resources through a new production facility. The development plan includes a purpose-built jack-up production facility located over an oil storage tank on the seabed. PDO was submitted to the authorities in December 2006.

Øst Frigg

Block	25/1 and 25/2
Development approval	14.12.1984
Cessation plan/decommissioning	Storting Proposition No. 8 (1998–1999) and in Storting White Paper No. 47 (1999–2000)
On stream	01.10.1988
Production ceased	22.12.1997
Total production over field lifetime	Gas: 9,2 billion scm. Condensate: 0,1 million scm.

Status: No activity.

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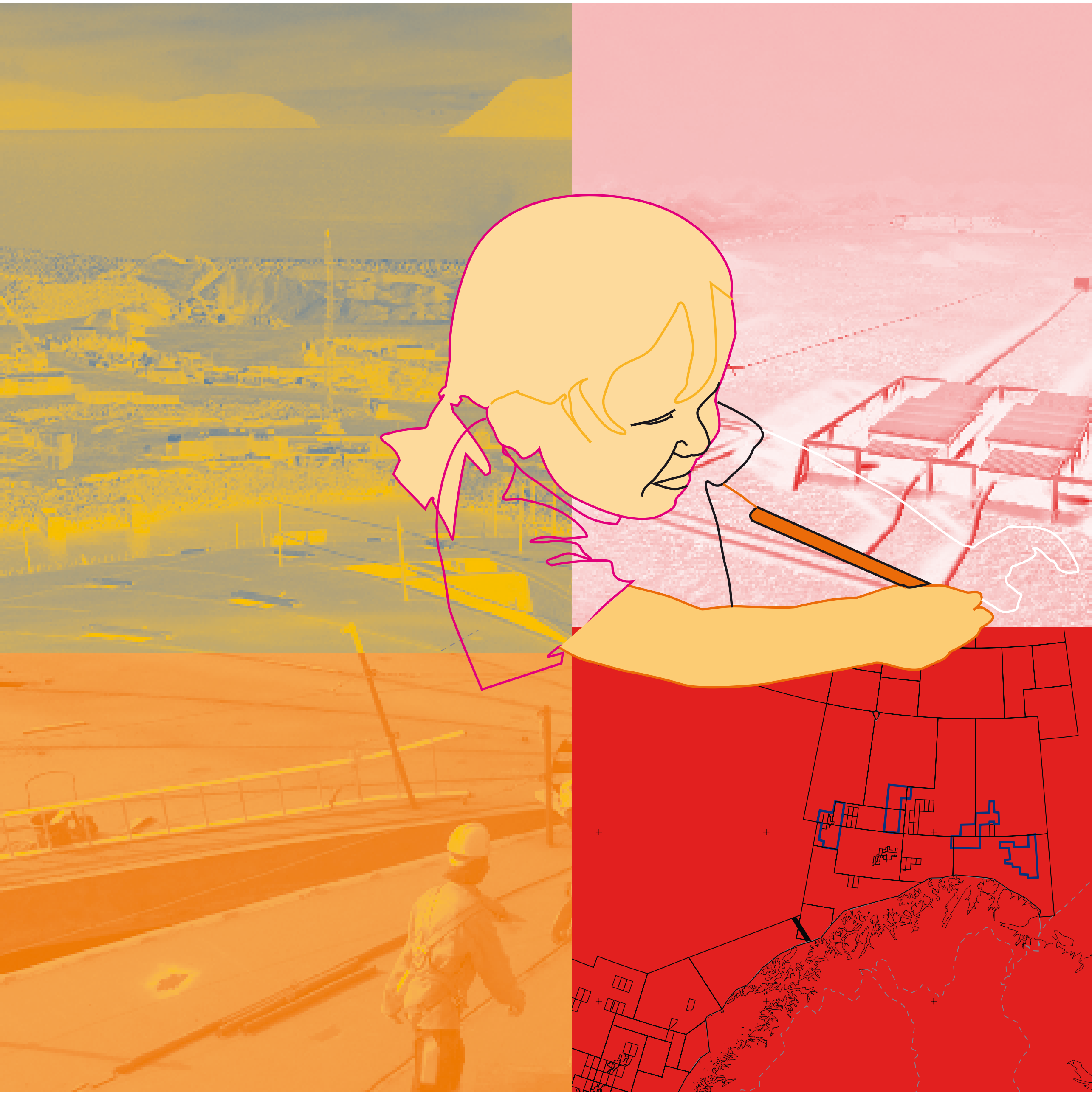
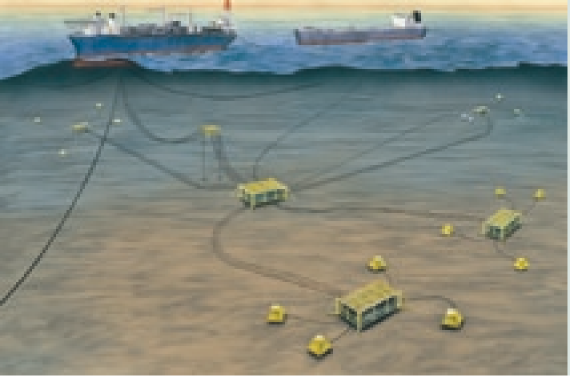
12 Fields under development





Alvheim

Block and production licence	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	
Operator	Marathon Petroleum Norge AS	
Licensees	Lundin Norway AS	15,00 %
	Marathon Petroleum Norge AS	65,00 %
	Norske ConocoPhillips AS	20,00 %
Recoverable reserves	**Original:** 25,5 million scm oil 5,6 billion scm gas	
Investment	Total investment is expected to be NOK 10,2 billion (2007 values) NOK 7,3 billion have been invested at 31.12.2006 (2007 values)	

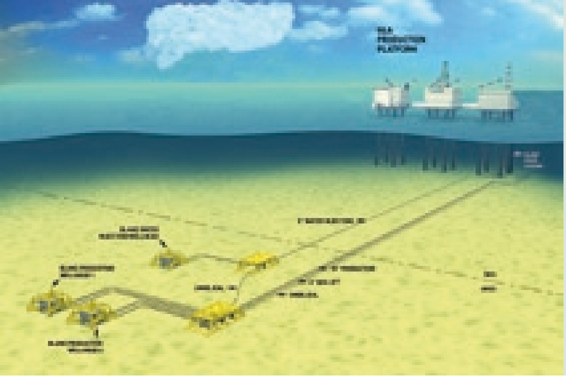
Development:
Alvheim is an oil and gas field in the northern part of the North Sea near the border to the British sector. The field comprises the three discoveries 24/6-2, 24/6-4 and 25/4-7. The sea depth in the area is 120-130 metres. Alvheim will be developed using a production vessel and subsea wells. The oil will be stabilised and stored in the production vessel.

Reservoir:
The Alvheim reservoir consists of sandstones deposited as turbidites from the Shetland Platform in the Lower Tertiary.

Recovery strategy:
Alvheim will be produced with aquifer drive.

Transport:
The oil will be exported by tankers. Processed rich gas from Alvheim will be transported in a new pipeline from Alvheim to the SAGE system on the UK continental shelf.

Status:
Planned production start-up for Alvheim is spring 2007.



Blane

Block and production licence	Block 1/2 – production licence 143 BS, awarded 2003 The Norwegian part of the field is 18,00 %, the British part is 82,00%	
Discovered	1989	
Development approval	01.07.2005	
Operator	Talisman Expro Limited	
Licensees	Talisman Energy Norge AS	18,00 %
	Bow Valley Petroleum (UK) Limited	12,50 %
	Eni UK Limited	13,90 %
	Eni ULX Limited	4,11 %
	Moc Exploration (U.K.) Limited	13,99 %
	Roc Oil (GB) Limited	12,50 %
	Talisman Expro Limited	25,00 %
Recoverable reserves (the Norwegian part)	**Original:** 0,8 million scm oil	
Investment	Total investment is expected to be NOK 0,4 billion (2007 values) NOK 0,4 billion have been invested at 31.12.2006 (2007 values)	

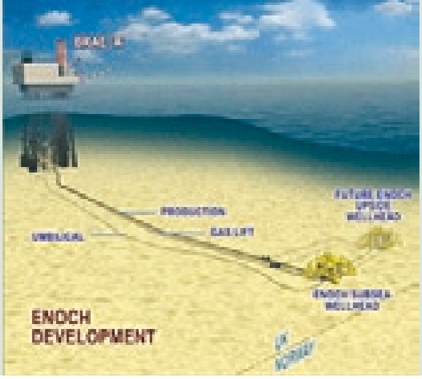
Development:
Blane is located in the southern part of the North Sea on the border to the British sector southwest of Ula. The field has been developed with subsea facilities connected to the Ula field. The subsea installations are placed on the British continental shelf. The sea in the area is approximately 70 metres deep.

Reservoir:
The reservoir consists of Paleocene marine sandstones.

Recovery strategy:
Produced water from Blane, Ula and Tambar will be mixed on Ula and used as injection water for maintaining the pressure on Blane. Gas lift may also be implemented after upgrading of the gas process capacity on Ula.

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

Status:
Production is planned to start in the first half of 2007.



Enoch

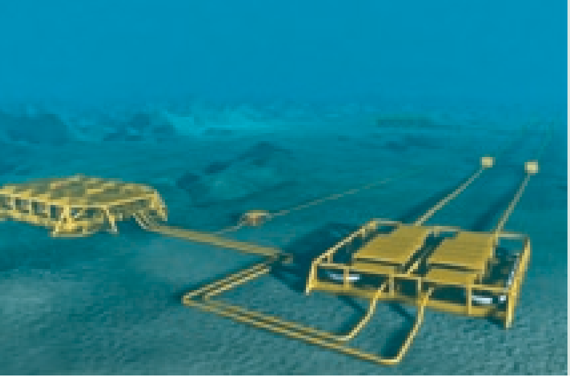
Block and production licence	Block 15/5 – production licence 048 B, awarded 2001 The Norwegian part of the field is 20,00%, the British is 80,00%
Discovered	1991
Development approval	01.07.2005
Operator	Talisman Expro Limited
Licensees	DONG E&P Norge AS 1,86 % Det Norske Oljeselskap AS 2,00 % Statoil ASA 11,78 % Total E&P Norge AS 4,36 % Bow Valley Petroleum (UK) Limited 12,00 % Dana Petroleum (E & P) Limited 8,80 % Dyas UK Limited 14,00 % Lundin North Sea Limited 1,20 % Petro-Canada UK Limited 8,00 % Roc Oil (GB) Limited 12,00 % Talisman Expro Limited 24,00 %
Recoverable reserves (the Norwegian part)	**Original:** 0,3 million. scm oil 0,1 billion scm gas
Investment	Total investment is expected to be 0,2 billion (2007 values) NOK 0,2 billion have been invested at 31.12.2006 (2007 values)

Development:
Enoch is located in the southern part of the North Sea, northwest of Sleipner, straddling the border to the British sector. The field has been developed with subsea facilities placed on the British continental shelf and connected to the British Brae field.

Recovery strategy:
The field will be produced by pressure depletion, but water injection may be implemented later if necessary.

Transport:
The well stream from Enoch will be routed to the Brae A facility on the British continental shelf for processing and onward transport in the existing pipeline to Cruden Bay. The gas will be sold to Brae.

Status:
Production is planned to start in 2007.



Ormen Lange

Block and production licence	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	
Operator	Norsk Hydro Produksjon AS	
Licensees	A/S Norske Shell	17,04 %
	DONG E&P Norge AS	10,34 %
	ExxonMobil Exploration & Production Norway AS	7,23 %
	Norsk Hydro Produksjon AS	18,07 %
	Petoro AS	36,48 %
	Statoil ASA	10,84 %
Recoverable reserves	**Original:**	
	375,2 million scm gas	
	22,1 billion scm condensate	
Investment	Total investment is expected to be 45,4 billion (2007 values)	
	NOK 12,2 billion have been invested at 31.12.2006 (2007 values)*	

**Total investment, including the land facilities, is expected to be NOK 64,7 billion (2007 values).*

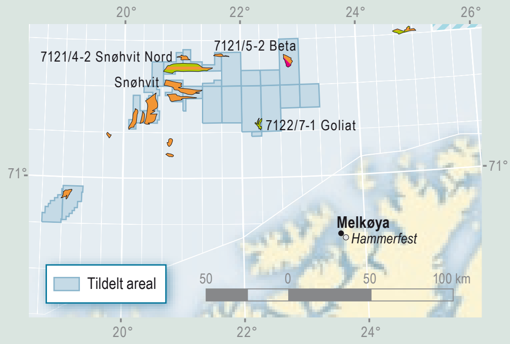
Development:
Ormen Lange lies in the Møre basin in the southern part of the Norwegian Sea. The field contains gas and some condensate. The sea depth in the area varies from 800 to 1100 metres. Ormen Lange is being developed with 24 wells drilled from three subsea templates. Four production wells will be ready for production start-up on 01.10.2007. Because the development area is located in the depression of the Storegga landslide, which occurred some 8100 years ago, there are great challenges related to the installation of templates and pipelines on the rough seabed. The deep waters also make the development complicated and has required development of new technology.

Reservoir:
The main reservoir is in sandstone from the Early Tertiary, about 2700 - 2900 metres below sea level.

Recovery strategy:
The recovery strategy is based on production by pressure depletion and subsequent gas compression.

Transport:
The unprocessed wellstream, consisting of gas and condensate, will be routed through two multi-phase pipelines to an onshore facility at Nyhamna in Aukra in Møre og Romsdal. At the plant at Nyhamna, the gas will be dried and compressed before being transported through the new gas export pipeline, Langeled, south via the Sleipner area and onward to the United Kingdom.

Status:
Gas production from Ormen Lange is planned to start in October 2007.



Snøhvit

Block and production licence	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
Operator	Statoil ASA

Licensees	Gaz de France Norge AS	12,00 %
	Hess Norge AS	3,26 %
	Petoro AS	30,00 %
	RWE Dea Norge AS	2,81 %
	Statoil ASA	33,53 %
	Total E&P Norge AS	18,40 %

Recoverable resources	**Original:** 160,6 billion scm gas 6,3 million tonn NGL 18,1 million scm condensate
Investment	Total investment is expected to be 16,7 billion (2007 values) NOK 8,1 billion have been invested at 31.12.2006 (2007 values) *

**Total investment, including the land facilities, is expected to be NOK 60.1 billion (2006 values)*

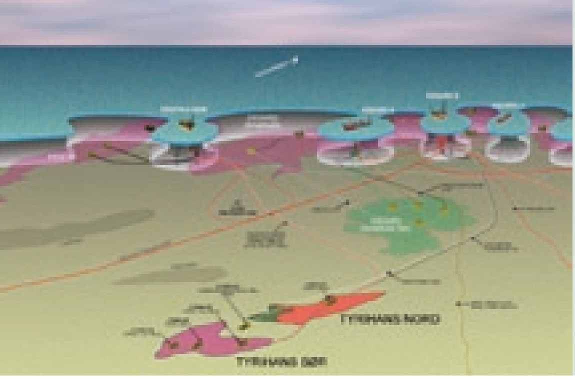
Development:
Snøhvit is located in the Barents Sea in the central part of the Hammerfest basin. The sea depth in the area is between 310 and 340 metres. Snøhvit is a gas field with condensate and an underlying oil zone. Snøhvit comprises several discoveries and deposits in the Askeladd and Albatross structures, in addition to Snøhvit. Approved development plan for the gas resources comprises subsea templates for 19 production wells and a CO_2 injection well. Production start-up is planned for 3rd quarter of 2007 with full production from 1st quarter of 2008.

Reservoir:
The Snøhvit field contains gas, condensate and oil in Lower and Middle Jurassic sandstones.

Recovery strategy:
The gas resources will be produced by pressure depletion. The approved development plan does so far not include recovery of the oil zone.

Transport:
The unprocessed wellstream, comprising natural gas incorporating CO_2, NGL and condensate will be transported through a 160 kilometres long pipeline to the Melkøya plant for processing. At Melkøya the gas will be processed and cooled to liquid gas (LNG). The CO_2 content in the gas will be separated at the Melkøya plant and returned to the field for injection in a formation below the oil and gas. LNG will be transported to the market by ship.

Status:
The licensees have decided to drill an appraisal well in the western part of Snøhvit in order to collect more information on the oil zone, planned for mid 2007.



Tyrihans

Block and production licence	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 in the Storting
Operator	Statoil ASA
Licensees	Eni Norge AS 6,23 % Mobil Development Norway AS 11,75 % Norsk Hydro Produksjon AS 12,00 % Statoil ASA 46,84 % Total E&P Norge AS 23,18 %
Recoverable reserves	**Original:** 29,0 million scm oil 29,3 billion scm gas 5,0 million tonn NGL
Investment	Total investment is expected to be 15,1 billion (2007 values) NOK 2,4 billion have been invested at 31.12.2006 (2007 values)

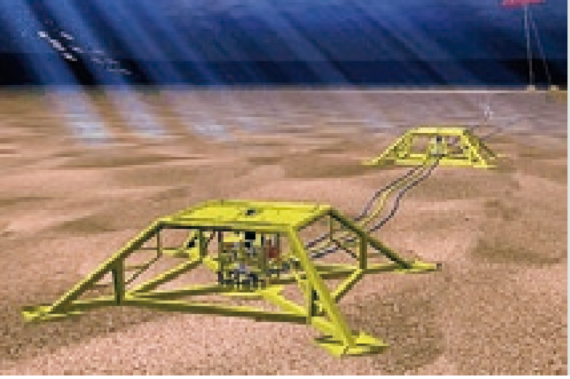
Development
Tyrihans is located in the Norwegian Sea about 25 kilometers southeast of Åsgard. The water depth in the area is approximately 270 metres. Tyrihans encompasses the discoveries 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord. The development solution chosen by the licensees is tie-in to Kristin for processing.

Reservoir
Tyrihans Sør has an oil column with a condensate rich gas cap. Tyrihans Nord contains gas condensate with an underlying oil column. The Garn formation is the main reservoir for both.

Recovery strategy
Recovery is based on gas injection from Åsgard B into Tyrihans Sør in the first years. In addition, subsea pumps will be used to inject seawater to further increase recovery. A decision has also been made to develop the oil zone in Tyrihans Nord.

Transport
Oil and gas from Tyrihans will be transported to Kristin for processing and further transport.

Status
Production start-up is planned for 2009 when there is available process capacity at Kristin.



Vilje

Block and production licence	Block 25/4 - production licence 036, awarded 1971	
Discovered	2003	
Development approval	18.03.2005 by the King in Council	
Operator	Norsk Hydro Produksjon AS	
Licensees	Marathon Petroleum Norge AS	46,90 %
	Norsk Hydro Produksjon AS	28,85 %
	Total E&P Norge AS	24,24 %
Recoverable reserves	**Original:**	
	8,3 million scm oil	
	0,4 billion scm gas	
Investment	Total investment is expected to be 2,6 billion (2007 values)	
	NOK 1,5 billion have been invested at 31.12.2006 (2007 values)	

Development:
Vilje is a small oil field located in the northern part of the North Sea, just north of the Heimdal field. The sea depth in the area is approximately 120 metres. The field will be developed with two subsea wells connected to Alvheim,

Reservoir:
The reservoir consists of Paleocene (early Tertiary) sandstones deposited as turbidites and is located approximately 2 150 metres below sea level. A 65 metres thick oil column in sandstones belonging to the Heimdal formation was proven in the discovery well.

Recovery strategy:
Production will be accomplished by aquifer drive.

Transport:
The well stream will be routed by pipeline to Alvheim, where the oil will be buoy-loaded to tankers.

Status:
Production start-up is planned for September 2007.

Volve

Block and production licence	Block 15/9 - production licence 046 BS, awarded 2006	
Discovered	1993	
Development approval	22.04.2005 by the Crown Prince Regent in Council	
Operator	Statoil ASA	
Licensees	ExxonMobil Exploration & Production Norway AS	30,40 %
	Norsk Hydro Produksjon AS	10,00 %
	PA Resources Norway AS	10,00 %
	Statoil ASA	49,60 %
Recoverable reserves	**Original:**	
	12,4 million scm oil	
	1,3 billion scm gas	
	0,2 million tonn NGL	
	0,1 million scm condensate	
Investment	Total investment is expected to be 2,3 billion (2007 values)	
	NOK 0,9 billion have been invested at 31.12.2006 (2007 values)	

Development:
Volve is an oil field located in the southern part of the North Sea approximately eight kilometres north of Sleiper Øst. The sea depth is approximately 80 metres. The development concept is a jack-up processing and drilling facility and a vessel for storing stabilized oil.

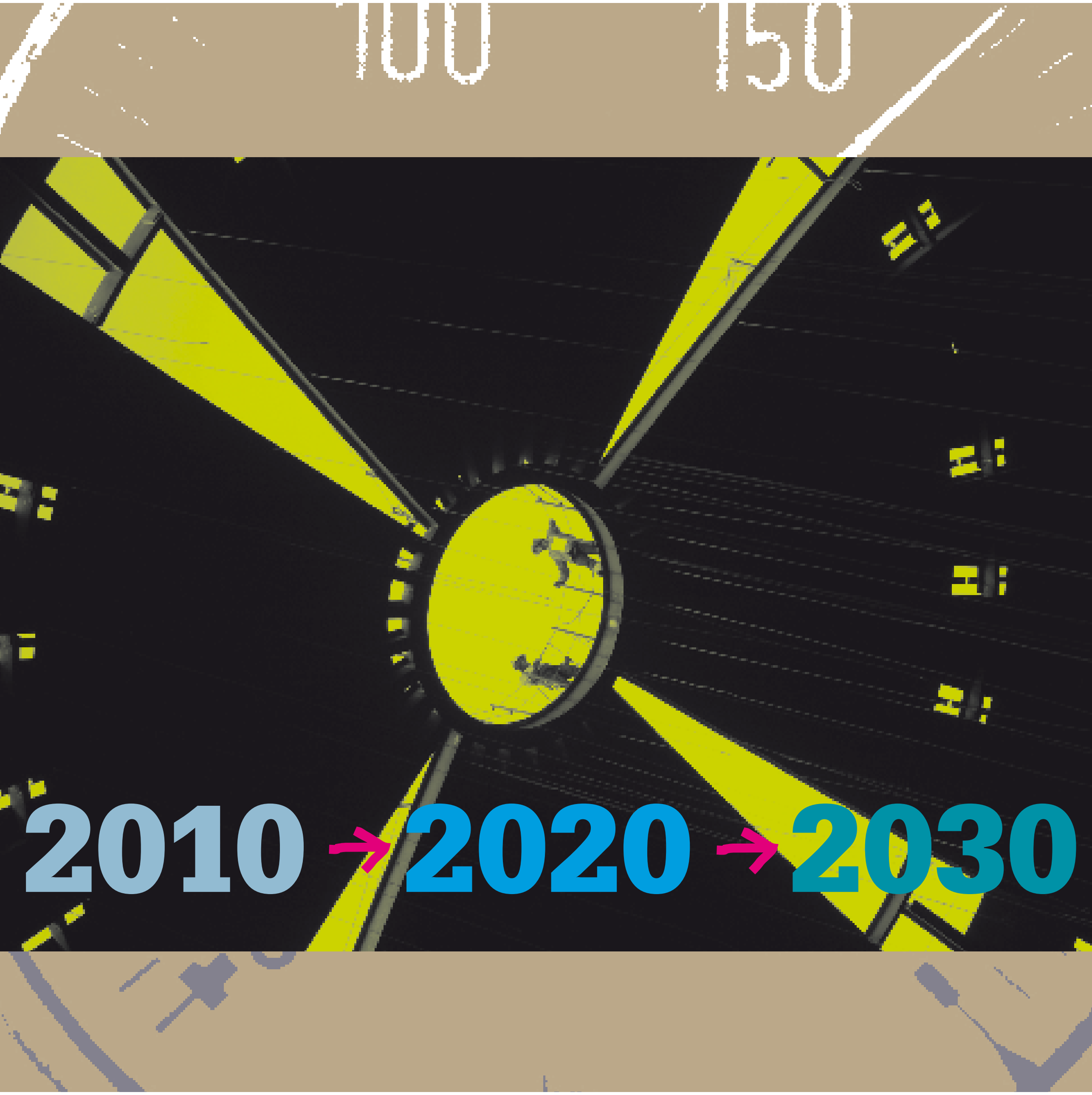
Reservoir:
The reservoir contains oil in a combined stratigraphic and structural trap with Jurrassic and Triassic sandstones in the Hugin formation. The western part of the structure is heavily faulted and it is uncertain if there is communication across the faults.

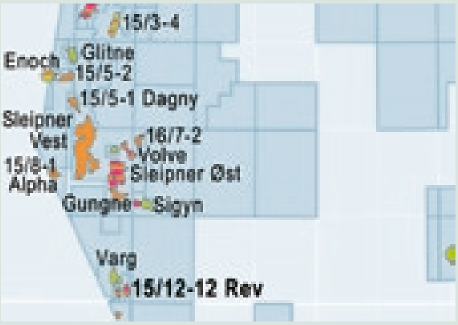
Recovery strategy:
Volve will be recovered by water injection.

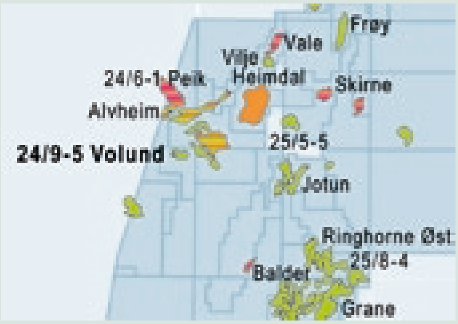
Transport:
The rich gas will be transported to Sleipner A and exported onwards from there.

Status:
Production start-up is planned for 2007.

13 Future developments







Development decided by the licensees

15/12-12 REV	Production licence 038 C, Operator: Talisman Energy Norge AS
Resources	Gas: 3,9 billion scm. Condensate: 0,6 million scm.

15/12-12 Rev was discovered in 2000 near the border between the Norwegian and British sectors and four kilometres south of the Varg field. The sea depth in the area is 90–110 metres. The reservoir is situated around a salt structure at a depth of about 3 000 metres, and consists of Upper Jurassic sandstones. The discovery has an oil zone with gas cap. Pressure measurements indicate that the reservoir is in pressure communication with the Varg field.

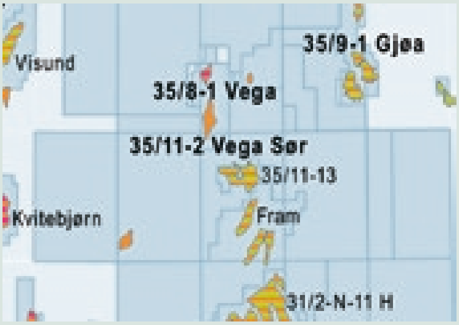
PDO was submitted to the authorities in 2006. Development will be based on subsea templates tied back to the Armada field on the British continental shelf. An appraisal well drilled on the east flank early in 2007 proved additional recourses. The well can later be used as a production well.

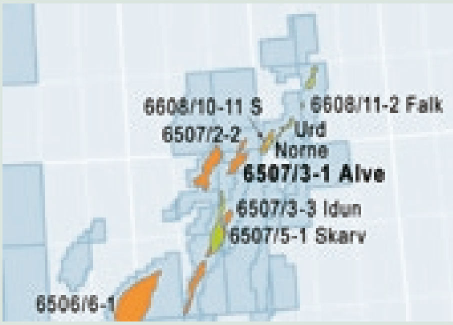
24/9-5 VOLUND	Production licence 150, Operator: Marathon Petroleum Norge AS
Resources	Oil: 7,2 million scm. Gas: 0,8 billion scm.

24/9-5 Volund is located just south of Alvheim and is an oil discovery made in 1994. The reservoir consists of sandstone of Paleogene age. Volund will be developed with subsea wells (three production wells and one water injection well) tied back to the Alvheim (FPSO), which is currently being built. The PDO was approved by the authorities 18.01.2007 and according to plan production will start in the spring of 2009.

35/8-1 VEGA	Production licence 248, Operator: Norsk Hydro Produksjon AS
Resources	Gas: 11,2 billion scm. NGL: 0,6 million tonnes Condensate: 2,0 million scm.

35/8-1 Vega is located north of the Fram field in the northern part of the North Sea. The sea depth in the area is approximately 370 metres. The discovery encompasses two separate gas/condensate deposits proven in well 35/8-1 in 1981 and 35/8-2 in 1982. The reservoirs belong to the Middle Jurassic Brent group and have high temperature, high pressure and relatively low permeability. Faults and shale layers may be sealing. The discoveries will be developed with two subsea templates tied back to the planned processing facility on Gjøa. A combined PDO for 35/8-1 Vega and 35/11-2 Vega Sør was submitted to the authorities in December 2006. Start of production is planned for October 2010.





35/9-1 GJØA	Production licence 153, Operator: Statoil ASA
Resources	Oil: 11,1 million scm. Gas: 32,6 billion scm. NGL: 5,6 million tonnes

35/9-1 Gjøa was discovered in 1989 and is located about 40 kilometres north of the Fram field. The sea depth in the area is approximately 360 metres. The reservoirs contain gas over a relatively thin oil zone in sandstones belonging to the Viking group of Middle to Upper Jurassic age, and Brent and Dunlin groups of Middle Jurassic age. The discovery comprises several tilted fault segments with partial uncertain communication and varying reservoir quality. Drive mechanism will be pressure depletion.

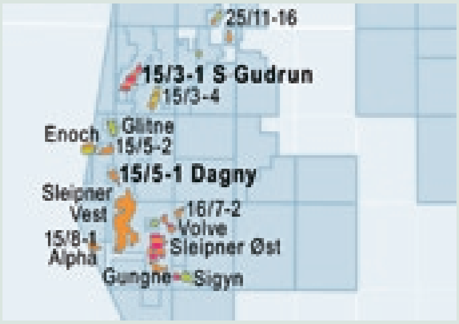
Statoil is operator in the development phase, while Gaz de France will take over the operatorship at production start-up. The development will include five subsea templates tied to a semi-submersible production and processing facility. Stable oil will be exported in a new 55 kilometre long pipeline which will be connected to Troll Oljerør II for further transport to Mongstad. The plan is to export the rich gas in a new 130 kilometre long pipeline to the FLAGS transportation system on the British continental shelf, for further transport to St. Fergus. A PDO was submitted to the authorities in December 2006.

35/11-2 VEGA SØR	Production licence 090 C, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 0,9 million scm. Gas: 9,1 billion scm. NGL: 0,5 million tonnes Condensate: 2,9 million scm.

35/11-2 Vega Sør was discovered in 1987 near the Fram field. The sea depth in the area is approximately 370 metres. The discovery is a gas/condensate deposit with an oil zone in Upper Brent. The development concept for the gas/condensate is a subsea template tied to Vega and the planned facility on Gjøa. A combined PDO for 35/8-1 Vega and 35/11-2 Vega Sør was submitted to the authorities in December 2006. Start of production is planned for October 2010. Development of the oil zone is evaluated in connection with the discovery 35/11-13 to the east of 35/11-2 Vega Sør.

6507/3-1 ALVE	Production licence 159 B, Operator: Statoil ASA
Resources	Gas: 5,8 billion scm. NGL: 0,9 million tonnes Condensate: 1,4 million scm.

6507/3-1 Alve was discovered in 1990 about 16 kilometres southwest of Norne. The sea depth in the area is 370 metres. The reservoir is sandstones in the Garn and Not formations of Middle Jurassic age. The discovery contains gas and condensate. A combined exploration and production well will be drilled in 2007 to prove possible additional resources in the underlying Ile and Tilje formations. The well will be used as a gas producer for draining the reservoir in the Garn- and Not formations at later stage. Alve will be connected to the Norne vessel with a pipeline. The gas will be transported via the Norne pipeline to Åsgard Transport and further on to Kårstø for export. A PDO was submitted to the authorities in January 2007 and was approved on 16 March 2007. Start of production is planned for October 2008 and the production is expected to continue until 2020 provided that the lifetime of the Norne vessel is extended. Potential discoveries in the Ile- and Tilje formations may be developed later, with production start-up 2009-2010.



Discoveries in the planning phase

This list does not comprise discoveries included in existing fields.

1/9-1 TOMMELITEN ALPHA	Production licence 044, Operator: ConocoPhillips Skandinavia AS
Resources	Oil: 6,7 million scm. Gas: 13,9 billion scm.

1/9-1 Tommeliten Alpha was proven in 1976. The sea depth in the area is approximately 80 metres. The discovery is located about 20 kilometres southwest of the Ekofisk field, near the border to the British sector. The discovery contains gas and condensate in Cretaceous chalk at a depth of 3500 metres. Three appraisal wells have been drilled on the discovery, the most recent being 1/9-7 in 2003. The licensees are evaluating the resource base and alternative development concepts. Production may start in 2010 at the earliest.

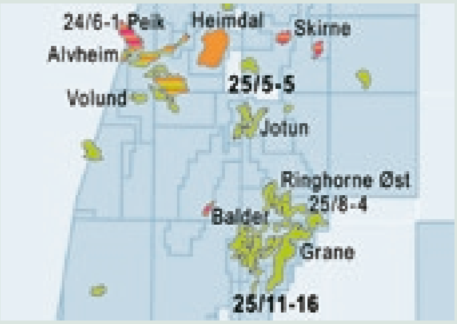
2/12-1 FREJA	Production licence 113, Operator: Hess Norge AS
Resources	Oil: 2,9 million scm. Gas: 0,6 billion scm.

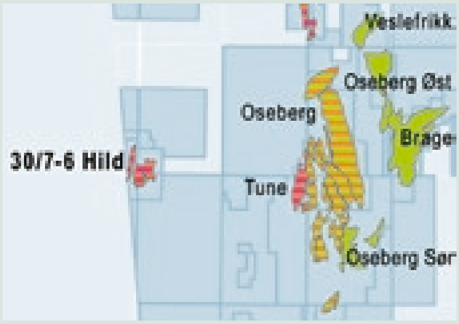
2/12-1 Freja was discovered in 1986, close to the border between the Danish and Norwegian sectors. The sea depth in the area is 70 metres. The reservoir is in Upper Jurassic sandstones. The reservoir is located at a depth of about 4900 metres, and contains oil and associated gas. 2/12-1 Freja is situated in a complex geological area between 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 Gert deposit on the Danish side of the border. The deposit will most likely be developed with a wellhead facility or subsea templates connected to existing infrastructure in the Danish sector.

15/3-1 S GUDRUN	Production licence 025, Operator: Statoil ASA
Resources	Oil: 15,6 million scm. Gas: 11,7 billion scm. NGL: 4,9 million tonnes Condensate: 0,7 million scm.

15/3-1 S Gudrun was discovered in 1975 about 40 kilometres north of the Sleipner area. The sea depth in the area is approximately 110 metres. The discovery contains oil and gas in Upper Jurassic sandstones, at a depth of 4000–4500 metres. The appraisal well 15/3-8 which was drilled in 2006, resulted in a reduced resource estimate. According to the plan, 15/3-1 S Gudrun will be developed together with the 15/3-4 discovery, which is located ten kilometres further to the southeast.

This development will most likely be accomplished with subsea facilities tied back to existing infrastructure. A PDO is planned to be submitted to the authorities in December 2008. 15/3-1 S Gudrun may start production in 2012 and 15/3-4 in 2013.





15/5-1 DAGNY	Production licence 029, 048, Operator: Statoil ASA
Resources	Gas: 5,2 billion scm. NGL: 0,7 million tonnes Condensate: 1,7 million scm.

15/5-1 Dagny is located northwest of Sleipner Vest. This small gas and condensate discovery was made in 1977. The discovery is divided between two production licences, 048 and 029. The reservoir is made up of Middle Jurassic sandstones in the Hugin formation. The recoverable resources have been increased based on remapping and a new reservoir model.

The development will most likely be a subsea facility connected to existing infrastructure on Sleipner A or to Sleipner T via the Alfa Nord segment. The development planning has been suspended in order to re-evaluate the resource potential in the area.

25/5-5	Production licence 102, Operator: Total E&P Norge AS
Resources	Oil: 3,5 million scm. Gas: 0,1 billion scm.

The 25/5-5 discovery was made in 1995, eight kilometres east of the Heimdal field. The sea depth in the area is approximately 120 metres. The reservoir is in Paleocene sandstones, deposited as turbidity currents from the west. The discovery well proved an oil column of 18 metres about 2 130 metres below sea level.

The discovery is situated close to existing infrastructure in an area with several other discoveries, and may be developed later on.

25/11-16	Production licence 169, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 3,6 million scm. Gas: 0,1 billion scm.

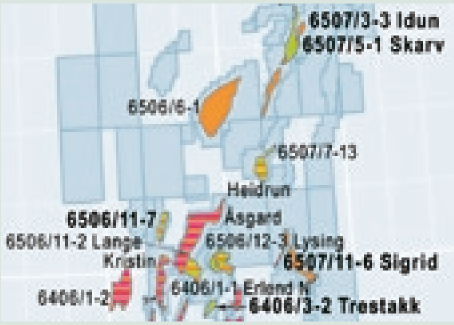
The 25/11-16 discovery was made in 1992 west of the Grane field. The sea depth in the area is 120 metres. The well proved oil and associated gas at a depth of about 1 750 metres, in Paleocene sandstones in the Heimdal formation. The discovery is located in an area with extensive sandstone reservoirs in a submarine fan system.

The most likely development solution is subsea templates tied back to Grane.

30/7-6 HILD	Production licence 040, 043, Operator: Total E&P Norge AS
Resources	Oil: 5,0 million scm. Gas: 15,6 billion scm. Condensate: 1,9 million scm.

30/7-6 Hild was discovered in 1979, near the border between the Norwegian and the British sectors. The sea depth in the area is 100–120 metres. The reservoir is complex, with gas and condensate at high temperatures and high pressure. The licensees are evaluating a phased development.

The development solution for phase 1 will be a subsea well tied back to the nearest infrastructure on the British continental shelf. PDO for Phase 1 is planned to be submitted to the authorities in the 3rd quarter of 2007. There are several alternative development solutions for phase 2.



34/10-23 VALEMON	Production licence 050, 193, Operator: Statoil ASA
Resources	Gas: 16,3 billion scm. NGL: 0,7 million tonnes Condensate: 5,4 million scm.

34/10-23 Valemon is located in blocks 34/11 and 34/10, just west of the Kvitebjørn field. The sea depth in the area is about 135 metres. Five exploration wells have been drilled on the discovery, the first in 1985, and gas has been proven in four of them. The discovery has a complex structure with many faults. The reservoir consists of Middle Jurassic sandstones in the Brent group and the Cook formation at a depth of approximately 4000 metres, with high pressures and high temperatures. The appraisal well 34/11-5 S was drilled from the Kvitebjørn facility in 2006. The well proved hydrocarbons in the Brent group and gave important information on the extension and characteristics of the reservoir. The operator is presently remapping the discovery. Based on updated resource estimates the licensees will evaluate various development solutions and tie-in possibilities. At the present, development with a fixed facility seems most likely.

35/11-13	Production licence 090 B, Operator: Norsk Hydro Produksjon AS
Resources	Oil: 6,4 million scm. Gas: 2,8 billion scm.

35/11-13 was discovered in 2005 north of the Fram field. The sea depth in the area is approximately 390 metres. The reservoir contains oil with a gas cap in sandstones in the Upper Jurassic Viking Group. The appraisal well 35/11-14 S drilled in the autumn of 2006, proved oil and gas in a new fault segment and gave important additional information about the discovery.

The development concept is expected to be subsea templates tied to Troll B. The production may start in 2012.

6406/3-2 TRESTAKK	Production licence 091, 091 B, Operator: Statoil ASA
Resources	Oil: 11,3 million scm. Gas: 2,0 billion scm. NGL: 0,6 million tonnes

6407/3-2 Trestakk is located centrally on the Halten Terrace. The sea depth in the area is approximately 300 metres. Exploration well 6406/3-2 was drilled in 1984 and proved oil in Middle Jurassic sandstone belonging to the Garn Formation. Appraisal well 6406/3-4, drilled 1986, penetrated the water zone in the Garn Formation. Large differences in the reservoir quality between the two wells in the Garn Formation are due to the formations belonging to different sedimentary facies.

The operator is preparing a PDO for the Trestakk deposit. Possible development concepts are a FPSO, tie to Åsgard A, Åsgard B or Kristin. Gas for injection may be supplied from Åsgard A. A joint development of 6407/3-2 Trestakk and 6507711-7 is being considered.

6506/11-7	Production licence 134 B, Operator: Statoil ASA
Resources	Oil: 8,3 million scm. Gas: 3,1 billion scm. NGL: 0,8 million tonnes

6506/11-7 is located in the north western part of the Halten Terrace, approximately 20 kilometres north of Kristin and 15 kilometres west of Åsgard. The sea depth in the area is 350 metres. The reservoir consists of a rotated and tilted fault block. The discovery well was drilled in 2001 and proved oil in Middle Jurassic sandstones belonging to the Garn and Ile formations. The reservoir in the Garn formation contains relatively homogenous deposits while the reservoir in the Ile formation is more heterogeneous.

The operator is preparing a PDO for the deposit. A subsea development with tie-in to the Åsgard facilities is most likely. A joint development of 6507/11-7 and 6407/3-2 Trestakk is being considered.

6507/3-3 IDUN	Production licence 159, Operator: Statoil ASA
Resources	Gas: 11,9 billion scm. NGL: 1,2 million tonnes Condensate: 0,3 million scm.

6507/3-3 Idun was proven in 1998. The discovery is located between Heidrun and Norne. The sea depth in the area is 390 metres. The reservoir contains gas and is made up of Middle Jurassic sandstones. The deposit is situated in a structurally faulted area in the Nordland II area, with the top of the reservoir at about 3 330 metres.

The licensees in 6507/3-3 Idun and 6507/5-1 Skarv have decided to proceed with a development solution based on a production vessel. Idun will be developed with a subsea facility connected to this production vessel. According to the plan, a PDO will be submitted to the authorities in summer 2007.

6507/5-1 SKARV	Production licence 159, 212, 212 B, 262, Operator: BP Norge AS
Resources	Oil: 16,4 million scm. Gas: 34,5 billion scm. NGL: 4,5 million tonnes Condensate: 4,0 million scm.

6507/5-1 Skarv was proven in 1998 and is located about 30 kilometres southwest of the Norne field and 40 kilometres north of Heidrun, mainly in production licence 212. The sea depth is approximately 400 metres. The discovery contains oil and gas in Jurassic and Cretaceous sandstones in three fault segments.

The licensees plan a development based on a production vessel and gas export through the Åsgard Transport. Injection of gas is planned for the first years to increase oil recovery. According to plan, a PDO will be submitted to the authorities in the summer 2007.

6507/11-6 SIGRID	Production licence 263, 263 B, Operator: Norsk Hydro Produksjon AS
Resources	Gas: 1,9 billion scm. NGL: 0,3 million tonnes Condensate: 0,4 million scm.

6507/11-6 Sigrid is a small gas discovery located in the Åsgard area. The sea depth in the area is approximately 290 metres. The discovery is expected to be developed with a subsea template and transport via Midgard to Åsgard B. The original plan to submit a PDO in 2006/2007 has now been postponed. Production start for the discovery is dependent on the plans for Åsgard.

7122/7-1 GOLIAT	Production licence 229, Operator: Eni Norge AS
Resources	Oil: 28,0 million scm. Gas: 10,6 billion scm.

7122/7-1 Goliat was proven in 2000 and is located 50 kilometres southeast of Snøhvit and 85 kilometres northwest of Hammerfest. The sea depth in the area is about 370 metres. The first exploration well proved oil in sandstones from the Upper Triassic to Lower Jurassic Ages, about 1100 metres below sea level. Well 7122/7-3, completed early in 2006, proved hydrocarbons in three different levels in Triassic sandstones. Oil and gas was proven in the main reservoir in the Realgrunnen subgroup of Upper Triassic age. In addition, oil was proven in the Snadd Formation of the same age and an oil column in the Kobbe Formation of Middle Triassic age. Further appraisal drilling was carried out in the autumn of 2006. The licensees are considering various development solutions. The main alternatives are a floating facility or subsea development tied to land. There are plans for further drilling activity in 2007.

14 Pipelines and onshore facilities

Figur 14.1 Existing and projected pipelines
(Source: Norwegian Petroleum Directorate)

The transport capacities quoted are based on standard assumptions for pressure, gas energy content, maintenance downtime and operational flexibility.

Gassled pipelines

Operator: Gassco AS

Licensees:

Petoro AS[1]	38.245 %
Statoil ASA	20.180 %
Norsk Hydro Produksjon AS	11.620 %
Total E&P Norge AS	8.086 %
ExxonMobil Exploration and Production Norway AS	5.298 %
Mobil Development Norway AS	4.267 %
Norske Shell Pipelines AS	4.140 %
Norsea Gas AS	2.839 %
Norske ConocoPhillips AS	1.946 %
Eni Norge AS	1.574 %
A/S Norske Shell	1.115 %
DONG E&P Norge AS	0.690 %

[1] Petoro is the licensee representing the State's Direct Financial Interest (SDFI). Petoro's participating interest in Gassled will be increased by approximately 8,4 per cent with effect from 1 January 2011, and the other parties' participating interests will be asjusted with 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 encompasses the following pipelines: Europipe I, Europipe II, Franpipe, Norpipe, Oseberg Gas Transport, Statpipe (including the transport-related facilities at Kårstø), Vesterled, Zeepipe and Åsgard Transport. Langeled was included in Gassled as of 1. September 2006. 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, terminating at Emden in Germany. Europipe I came into service in 1995. It has a capacity of about 46-54 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 21.7 billion (2007 value). In addition to the pipeline, investments also include the terminal at Dornum and the Europipe Metering Station 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 650 kilometres from Kårstø to Dornum in Germany, and became operational in 1999. With a capacity of about 71 million scm per day, Europipe II has been built for an operating life of 50 years. Total investment at start-up was approximately NOK 9.8 billion (2007 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 by 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 Gaz de France owns 35 per cent. The pipeline became operational in 1998. Franpipe has a capacity of about 52 million scm per day. It has been built for an operating life of 50 years. The total investment at start-up was approximately NOK 10.1 billion (2007 value).

(Agreement between Norway and France concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to France. See Storting Proposition No. 44 (1996–1997) and Recommendation No. 172 (1996–1997).)

Norpipe Gas pipeline

This 36-inch line 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 to pump the gas southwards. The compressors on one of these installations have now been shut down. The transport capacity is approximately 35 million scm per day without using the compressor capacity on the B11 riser facility. Capacity will increase to 42–43 million scm per day if the B11 compressors are used. Norpipe has been built for an operating life of at least 30 years. Its technical life is under constant review. Total investment at start-up was approximately NOK 27.0 billion (2007 value).

(Agreement between Norway and Germany concerning the transmission of petroleum through a pipeline from the Ekofisk field and adjacent areas to Germany. See 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. 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 2.0 billion (2007 value).

Statpipe

This 880-kilometres pipeline system includes a riser facility and a gas processing plant at Kårstø. The pipeline 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 25 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 Heimdal riser facility to Draupner S, with a capacity of about 30 million scm per day. The third section is a 36-inch pipeline running for roughly 203 kilometres from Draupner S to Ekofisk, 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 46.7 billion (2007 value), excluding the gas processing plant at Kårstø.

Vesterled

This 32-inch pipeline runs for about 350 kilometres from the Heimdal riser facility to St. Fergus in the UK and became operational in 1978. It has a capacity of about 38.6 million scm/day. Total investment in Vesterled at start-up was approximately. NOK 33 billion (2007 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. See Storting Proposition No. 73 (1998–1999) and Recommendation No. 219 (1998–1999)).

Zeepipe

Zeepipe I comprises a 40-inch pipeline running for about 814 kilometres from Sleipner 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 41 million scm per day. Zeepipe I also includes a 30-inch pipeline between Sleipner 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 303 kilometres long and has a capacity of 72 million scm per day. Zeepipe II B is a 40-inch pipeline running for about 300 kilometres, starting at the Kollsnes gas treatment plant and ending at Draupner E. The pipeline became operational in 1997. Zeepipe II B 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 24.7 billion (2007 value).

(Agreement between Norway and Belgium concerning the transmission of gas from the Norwegian continental shelf and other areas through a pipeline to Belgium. See 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 about 69 million scm/day. Åsgard Transport is built for an operating life of 50 years, with total investment at start-up of approximately NOK 10.7 billion (2007 value).

Langeled

The Langeled system will transport gas from the land facilities for Ormen Lange at Nyhamna via a tie-in at the Sleipner riser facility to a new receiving terminal at Easington on the eastern coast of the UK. This system will comprise a 42-inch pipeline from Nyhamna to the Sleipner riser (northern leg) and a 44-inch line from Sleipner to Easington (southern leg). Capacity will be just over 80 million scm/day in the northern leg and about 70 million scm/day in the southern leg. The system will have an overall length of roughly 1 200 kilometres. The southern leg became operational in October 2006, with the northern following in October 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 according to plan included in Gassled in the autumn of 2006. Total investment at start-up is expected to be NOK 17.4 billion (2007 values)

Kollsnes gas processing plant

The gas processing plant at Kollsnes in the municipality of Øygarden in Hordaland County 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 a pipeline to Sleipner and Draupner.

Kollsnes also delivers a small amount of gas to the LNG plant at the Gasnor-Kollsnes Industrial Park. Following a stabilisation process, the condensate is sent on to the Vestprosess plant at Mongstad. This plant was upgraded in 2004 with an NGL extraction plant to treat 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 1 October 2006.

Kårstø gas and condensate processing plant

Rich gas is processed at the Kårstø gas processing facility and the products, which are dry gas, ethane, propane, iso-butane and naphtha, are separated. 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 field. 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 in liquid form by ship.

Processing facilities at Kårstø comprise four extraction/fractionation lines for methane, ethane, propane, butanes and naphtha, plus a fractionation line for stabilising condensate. The capacity of the gas processing facilities prior to the latest expansion in 2005 was 70 million scm rich gas per day. 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 from 620,000 tonnes 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%
	ChevronTexaco Norge AS	7.56%
Investment	Total investment at start-up was approximately NOK 1.15 billion (2007 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 November 2000.

Grane Gas Pipeline

Operator	Norsk Hydro Produksjon AS
Licensees	As for the Grane field
Investment	Total investment at start-up was approximately NOK 0.31 billion (2007 value)
Operating lifetime	The technical operating life is 30 years
Capacity	Approximately NOK 3.6 billion scm per year

The pipeline commenced operation in September 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	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	43.60%
	ExxonMobil Exploration and Production Norway AS	25.60%
	Norsk Hydro Produksjon AS	24.40%
	Norske ConocoPhillips AS	6.40%
Investment	Total investment at start-up was approximately NOK 1.65 billion (2007 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 September 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 ASA	19.06%
	Norske ConocoPhillips AS	18.13%
	Eni Norge AS	5.00%
Investment	Total investment at start-up was approximately NOK 2.9 billion (2007 value) in pipelines and the terminal	
Operating lifetime	The licence expires on 31 December 2020	
Capacity	2.2 billion scm gas per year	

This 16-inch gas pipeline runs for 250 kilometres from the Heidrun field on Haltenbanken in the Norwegian Sea to Tjeldbergodden in the municipality of Aure in Møre og Romsdal county, where Statoil ASA and Norske ConocoPhillips AS have built a methanol plant close to the receiving terminal. This plant uses Heidrun gas to produce methanol. Gas deliveries to the methanol plant are approximately 0.7 billion scm per year.

Heidrun Gas Export

Operator	Statoil ASA[1]	
Licensees	Petoro AS	58.16%
	Norske ConocoPhillips AS	24.31%
	Statoil ASA	12.41%
	Eni Norge AS	5.12%
Investment	Total investment at start-up was approximately NOK 0.95 billion (2007 value)	
Operating lifetime	The technical operating lifetime is 50 years	
Capacity	Approximately 4.0 billion scm per year	

[1] The operatorship is due to be transferred to Gassco AS.

This 16-inch pipeline runs roughly 37 kilometres from the Heidrun field to the Åsgard Transport system. It became operational in February 2001.

Kvitebjørn Oil Pipeline (KOR)

Operator	Statoil ASA	
Licensees	Statoil ASA	43.55 %
	Petoro AS	30.00 %
	Norsk Hydro Produksjon AS	15.00 %
	Total E&P Norge AS	5.00 %
	Enterprise OIl Norge AS	6.45 %
Investment	Total investment at start-up was approximately NOK 0.52 billion (2007 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 an existing Y-connection on Troll Oil Pipeline II. The pipeline became operational in the second half of 2004.

Norne Gas Transport System (NGTS)

Operator	Gassco AS	
Licensees	Petoro AS	54.00%
	Statoil ASA	31.00%
	Norsk Hydro Produksjon AS	8.10%
	Eni Norge AS	6.90%
Investment	Total investment at start-up was approximately NOK 1.25 billion. (2007 value).	
Operating lifetime	Technical operating lifetime is 50 years	
Capacity	Approximately 3.6 billion scm per year	

This 16-inch pipeline runs 126 kilometres from Norne to the Åsgard Transport system. It became operational in February 2001.

Tampen Link

Operator	Statoil ASA	
Licensees	Statoil ASA	43.9 %
	ExxonMobil Exploration and Production Norway AS	18.2 %
	A/S Norske Shell	12.2 %
	Norsk Hydro Produksjon AS	10.5 %
	Norske ConocoPhillips AS	8.2 %
	Petoro AS	7.0%
Investment	Total investment at start-up is estimated at approximately NOK 1.9 billion (2007 value). This figure also includes necessary modifications on Statfjord B.	
Capacity	Approximately NOK 11 billion scm per year	

As part of the Statfjord Late Phase Project, a new 23.2 kilometres long, 32-inch gas pipeline will be laid between the Statfjord field and a point on the FLAGS pipeline, 1.4 kilometres south of the Brent Alpha facility. About 15.5 kilometres of the new gas export pipeline will be on the British side of the border. In addition to having capacity to transport all gas produced on Statfjord, this pipeline will be designed to enable export of gas volumes up to the capacity in the FLAGS pipeline. The date for completing Tampen Link is planned for October 2007. The plan for installation and operation was approved in 2005.

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 ASA	15.00%
	Eni Norge AS	6.52%
	Norsk Hydro Produksjon AS	3.50%
	SDFI	5.00%
Investment	Total investment at start-up was approximately NOK 16.7 billion (2007 value)	
Operating lifetime	The pipeline has been designed for an operating lifetime 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 about 810,000 bbls per day.	

The Norpipe Oil Pipeline crosses the British continental shelf, with landfall at Teesside in the UK. 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. See Storting Proposition No. 110 (1972–1973) and Recommendation No. 262 (1972–1973).)

Oseberg Transport System (OTS)

Operator	Norsk Hydro Produksjon AS	
Licensees	Petoro AS	48.38%
	Norsk Hydro Produksjon AS	22.24%
	Statoil ASA	14.00%
	Total E&P Norge AS	8.65%
	Mobil Development Norway AS	4.33%
	Norske ConocoPhillips AS	2.40%
Investment	Total investment at start-up was approximately NOK 10.0 billion. (2007 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 Oseberg licensees have established a separate partnership to operate this pipeline.

Sleipner Øst Condensate pipeline

Operator	Statoil ASA	
Licensees	Statoil ASA	49.60%
	ExxonMobil Exploration and Production Norway AS	30.40%
	Norsk Hydro Produksjon AS	10.00%
	Total E&P Norge AS	10.00%
Investment	Total investment at start-up was approximately NOK 1.65 billion. (2007 value)	
Capacity	200,000 bbls per day	

This 20-inch pipeline transports unstabilised condensate from Sleipner A to Kårstø.

Troll Oil Pipeline

Operator	Statoil ASA	
Licensees	Petoro AS	55.77%
	Statoil ASA	20.85%
	Norsk Hydro Produksjon AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start-up was approximately NOK 1.25 billion. (2007 value)	
Operating lifetime	Troll Oil Pipeline I 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 September 1995.

Troll Oil Pipeline II

Operator	Statoil ASA	
Licensees	Petoro AS	55.77%
	Statoil ASA	20.85 %
	Norsk Hydro Produksjon AS	9.73%
	A/S Norske Shell	8.29%
	Total E&P Norge AS	3.71%
	Norske ConocoPhillips AS	1.66%
Investment	Total investment at start up was approximately NOK 1.1 billion.(2007 value)	
Operating lifetime	Troll Oil Pipeline II 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 carry 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 on 1 November 1999. Oil from Fram and Kvitebjørn is transported through Troll Oil Pipeline II. The licence period for the pipeline lasts to 2023.

Other land facilities

Mongstad crude oil terminal

Owner	Statoil ASA	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 buoy loader shuttle tankers, which have a sailing range confined to northwest Europe. By storing and transshipping crude at Mongstad, however, Statoil can sell the oil to more distant destinations. Mongstad is also the receiving terminal for the oil pipelines from Troll B, Troll C, Troll Blend (Fram) and Kvitebjørn fields, as well as shuttle tankers from Heidrun.

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 Norsk Hydro Produksjon AS (the refrigerated LPG storage and transfer system to ships) and Vestprosess DA (export facility to Vestprosess).

The Sture oil terminal at Stura in Øygarden municipality near Bergen receives oil and condensate via the pipeline from the Oseberg A facility as well as 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 December 1988. It incorporates two jetties 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. The Ministry of Petroleum and Energy approved an upgrading of the facility in March 1998. A fractionation plant which came on line 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 ASA	81.70%
	Norske ConocoPhillips AS	18.30%

Plans to utilise gas from Heidrun as feedstock for methanol production at Tjeldbergodden in the municipality of Aure in Nordmøre were approved by the Storting in 1992. The methanol plant began production on 5 June 1997. Gas deliveries through the Haltenpipe line total 0.7 billion scm per year, which yield 830,000 tonnes of methanol.

An air separation plant, Tjeldbergodden Luftgassfabrikk DA, has been built in association with the methanol facility. This partnership has also constructed a small gas fractionation and liquefaction plant with an annual capacity of 35 million scm.

Vestprosess

Ownership	Petoro AS	41.00%
	Statoil ASA	17.00%
	Norsk Hydro Produksjon AS	17.00%
	Mobil Exploration Norway Inc.	10.00%
	A/S Norske Shell	8.00%
	Total E&P Norge AS	5.00%
	Norske ConocoPhillips AS	2.00%

The Vestprosess DA partnership owns and operates a system to transport and process NGL (wet gas). These facilities came on stream in December 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 feedstock, while the LPG is fractionated in a dedicated process into propane and butane. These products are stored in rock caverns before export. The Vestprosess plant utilises surplus energy and utilities from the refinery.

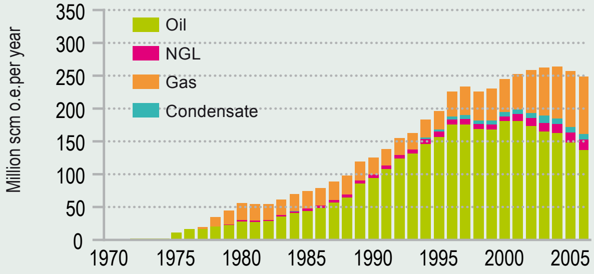
Appendix

Appendix 1 Historical statistics

Table 1.1 The state's revenues from petroleum activities (MNOK)

Year	Ordinary tax	Special tax	Production fee	Area fee	CO_2 tax	Net chash 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	78 200	133 700	0	500	3 400	126 700	14 000

(Source: State accounts, 2006 from the National Budget for 2007 and preliminary accounting figures)



Total petroleum production

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

Table 1.2 Petroleum production on the Norwegian continential shelf, millions of standard cubic meter oil equivalents

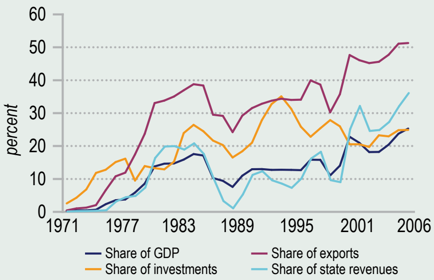
Year	Oil	Gas	Condensate	NGL	Total production
1971	0.357	0.000	0.000	0.000	0.357
1972	1.927	0.000	0.000	0.000	1.927
1973	1.870	0.000	0.000	0.000	1.870
1974	2.014	0.000	0.000	0.000	2.014
1975	10.995	0.000	0.000	0.000	10.995
1976	16.227	0.000	0.000	0.000	16.227
1977	16.643	2.655	0.002	0.000	19.300
1978	20.644	14.201	0.021	0.000	34.866
1979	22.478	20.670	0.044	1.128	44.319
1980	28.221	25.088	0.048	2.440	55.798
1981	27.485	24.951	0.048	2.168	54.652
1982	28.528	23.960	0.043	2.286	54.817
1983	35.645	23.613	0.041	2.680	61.979
1984	41.093	25.963	0.064	2.642	69.762
1985	44.758	26.186	0.076	2.968	73.987
1986	48.771	26.090	0.061	3.845	78.767
1987	56.959	28.151	0.055	4.117	89.281
1988	64.723	28.330	0.047	4.846	97.945
1989	85.983	28.738	0.053	4.898	119.672
1990	94.542	25.479	0.048	5.011	125.081
1991	108.510	25.027	0.057	4.897	138.492
1992	123.999	25.834	0.054	4.959	154.846
1993	131.843	24.804	0.554	5.518	162.720
1994	146.282	26.842	2.830	7.122	183.075
1995	156.776	27.814	3.726	7.942	196.257
1996	175.422	37.407	4.442	8.232	225.503
1997	175.914	42.950	6.401	8.074	233.338
1998	168.744	44.190	5.999	7.390	226.322
1999	168.690	48.479	6.497	6.992	230.658
2000	181.181	49.748	6.277	7.225	244.431
2001	180.884	53.895	6.561	10.924	252.264
2002	173.649	65.501	8.020	11.798	258.968
2003	165.475	73.124	11.060	12.878	262.537
2004	162.777	78.465	9.142	13.621	264.006
2005	148.137	84.963	8.422	15.735	257.257
2006	136.574	87.614	7.989	16.671	248.848

(Source: The Norwegian Petroleum Directorate)

Table 1.3 Value creation, exports, employment, investment 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	691	
1972	205	314	200	1 192	
1973	242	504	300	2 326	
1974	589	1 089	900	5 138	
1975	3 557	3 943	2 200	7 291	
1976	6 362	7 438	2 700	9 270	
1977	7 693	8 852	4 000	10 589	
1978	13 575	15 117	6 100	9 228	
1979	22 229	24 788	7 900	9 061	
1980	42 722	44 638	9 700	10 119	
1981	52 003	52 432	12 200	14 462	4 133
1982	57 799	57 623	13 100	15 909	5 519
1983	69 427	68 082	13 900	27 028	5 884
1984	86 313	82 504	15 800	32 244	7 491
1985	93 384	90 098	17 700	32 839	7 830
1986	57 174	57 239	18 000	33 155	6 654
1987	57 136	58 301	17 800	35 247	4 951
1988	47 784	51 720	18 700	29 680	4 151
1989	74 692	76 681	18 600	31 957	5 008
1990	93 530	92 451	19 200	32 223	5 137
1991	98 904	101 015	19 700	43 065	8 137
1992	99 787	101 187	20 900	49 512	7 680
1993	105 139	108 463	22 300	57 579	5 433
1994	109 989	113 099	22 500	54 653	5 011
1995	117 226	121 169	21 700	48 583	4 647
1996	161 247	167 200	23 000	47 878	5 455
1997	174 205	177 825	24 000	62 494	8 300
1998	123 564	128 807	28 000	79 216	7 577
1999	171 381	173 428	27 000	69 096	4 993
2000	334 632	326 658	29 000	53 589	5 274
2001	318 408	322 291	32 000	57 144	6 815
2002	274 915	283 343	31 000	54 000	4 476
2003	286 206	291 220	29 000	64 362	4 134
2004	351 669	347 926	30 000	71 473	4 010
2005	456 660	439 899	32 000	88 478	7 537
2006	538 484	509 189	31 000	95 740	11 718

(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 investment	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	0.19	1.04	6.56	0.16
1974	0.40	1.82	11.61	0.25
1975	2.09	6.36	12.56	0.38
1976	3.28	10.54	14.86	3.07
1977	3.52	11.68	15.92	4.38
1978	5.63	17.23	9.27	4.77
1979	8.35	23.47	13.68	7.31
1980	13.58	32.80	13.03	16.27
1981	14.41	33.58	12.69	19.76
1982	14.48	34.80	15.00	19.90
1983	15.66	36.69	23.71	18.86
1984	17.31	38.55	26.18	20.74
1985	16.90	38.16	24.26	17.50
1986	10.01	29.29	21.43	10.13
1987	9.17	28.91	20.04	3.21
1988	7.33	23.99	16.27	1.02
1989	10.74	28.99	18.15	5.20
1990	12.70	31.28	20.76	11.14
1991	12.75	32.60	27.65	12.25
1992	12.52	33.51	32.53	9.49
1993	12.54	34.12	34.84	8.50
1994	12.52	33.76	31.08	7.24
1995	12.43	33.83	25.64	10.06
1996	15.61	39.69	22.60	16.14
1997	15.57	38.42	25.13	18.15
1998	10.84	30.00	27.62	9.56
1999	13.82	35.49	25.74	8.93
2000	22.59	47.39	20.31	25.07
2001	20.72	45.82	20.28	32.07
2002	17.94	44.96	19.49	24.49
2003	17.96	45.35	23.03	24.80
2004	20.18	47.49	22.68	27.25
2005	23.50	50.84	24.57	32.01
2006	25.07	51.07	24.66	36.00

(Source: Statistics Norway. Ministry of Finance (National Budget for 2007). Ministry of Petroleum and Energy)

Appendix 2 The petroleum resources

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. 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
Yme	7.9				7.9	1987
Øst Frigg		9.2		0.1	9.3	1973
Historical production	**46.2**	**228.6**	**3.7**	**0.9**	**282.9**	
Balder[a)]	35.7	0.7			36.4	1967
Brage	47.3	2.3	0.9		51.4	1980
Draugen	113.7	1.2	1.8		118.2	1984
Ekofisk	377.4	131.3	11.8		531.2	1969
Eldfisk	83.6	36.5	3.6		126.9	1970
Embla	9.2	3.1	0.4		13.0	1988
Fram	7.2				7.2	1992
Gimle	0.6	0.1	0.0		0.7	2004
Glitne	7.0				7.0	1995
Grane	30.8				30.8	1991
Gullfaks[b]	329.2	22.2	2.5		356.1	1978
Gullfaks Sør[c]	27.2	16.2	1.9		47.0	1978
Gungne[3]			1.3	4.0	6.6	1982
Gyda[d)]	33.5	5.6	1.8		42.6	1980
Heidrun	115.7	8.3	0.4		124.8	1985
Heimdal	6.4	44.4			50.8	1972
Hod	8.5	1.5	0.2		10.4	1974
Huldra	4.2	12.0	0.1		16.4	1982
Jotun	20.9	0.8			21.6	1994
Kristin	1.1	2.8	0.6	2.1	7.1	1997
Kvitebjørn	5.3	10.5	0.9		17.6	1994
Mikkel	0.2	5.5	1.5	2.2	10.6	1987
Murchison	13.5	0.3	0.3	0.0	14.4	1975
Njord	21.0				21.0	1986

Field	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. mill scm o.e.	Year of discovery[2)]
Norne	72.7	5.0	0.6		78.7	1992
Oseberg[e)]	334.8	16.0	4.3		358.8	1979
Oseberg Sør	28.1	4.3			32.5	1984
Oseberg Øst	16.1	0.2			16.3	1981
Ringhorne Øst	0.9	0.0			1.0	2003
Sigyn		3.3	1.3	3.8	9.5	1982
Skirne	0.8	3.1			3.9	1990
Sleipner Vest og Sleipner Øst[3) f)]		135.8	17.3	54.0	222.6	1974
Snorre	146.6	5.6	4.3		160.5	1979
Statfjord	551.5	53.6	14.2	0.1	632.3	1974
Statfjord Nord	33.5	2.1	0.7		37.0	1977
Statfjord Øst	31.9	3.2	1.1		37.2	1976
Sygna	8.9				8.9	1996
Tambar	6.8		0.2		7.1	1983
Tor	22.3	10.7	1.2		35.2	1970
Tordis[g]	48.6	3.7	1.4		54.8	1987
Troll[h]	181.1	270.2	1.9	4.3	459.3	1979
Tune	2.9	12.5	0.1		15.6	1996
Ula	67.8	3.8	2.5		76.4	1976
Urd	2.2	0.1	0.0		2.3	2000
Vale	0.6	0.5			1.1	1991
Valhall	92.7	18.4	3.0		116.8	1975
Varg	9.7				9.7	1984
Veslefrikk	47.8	2.2	1.2		52.3	1981
Vigdis	36.7	0.6	0.5		38.2	1986
Visund	14.1	1.4	0.1		15.7	1986
Åsgard	50.4	52.2	9.0	17.1	136.8	1981
Producing fields	**3108.5**	**913.8**	**94.8**	**87.7**	**4290.1**	
Total sold and delivered	**3154.7**	**1142.4**	**98.5**	**88.7**	**4572.9**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year of the first discovery well drilled
3) Gas production from Gungne, Sleipner Vest and Sleipner Øst are metered collectively
a) Balder also includes Ringhorne
b) Gullfaks also includes Gullfaks Vest
c) Gullfaks Sør also includes Gulltopp, Gullveig, Rimfaks and Skinnfaks
d) Gyda also includes Gyda Sør
e) Oseberg also includes Oseberg Vest
f) Sleipner Øst also includes Loke
g) Tordis also includes Tordis Øst and Borg
h) Troll also includes TOGI

(Source: Norwegian Petroleum Directorate)

Table 2.2 Reserves in fields in production or fields with approved plan for development and operation

Field	Reserves mill. scm o.e.	Year of discovery[4)]	Operator at 31.12.2006	Production licence/ unit area
Alvheim[1)]	31.1	1998	Marathon Petroleum Norge AS	036 C, 088 BS, 203
Balder	56.7	1967	ExxonMobil Exploration and Production Norway AS	001
Blane[1)]	0.9	1989	Talisman Expro Limited	Blane
Brage	55.0	1980	Norsk Hydro Produksjon AS	Brage
Draugen	144.8	1984	A/S Norske Shell	093
Ekofisk	722.2	1969	ConocoPhillips Skandinavia AS	018
Eldfisk	183.4	1970	ConocoPhillips Skandinavia AS	018
Embla	17.4	1988	ConocoPhillips Skandinavia AS	018
Enoch[1)]	0.5	1991	Talisman Expro Limited	Enoch
Fram	31.2	1992	Norsk Hydro Produksjon AS	090
Gimle	5.0	2004	Statoil ASA	Gimle
Glitne	8.3	1995	Statoil ASA	048 B
Grane	112.4	1991	Norsk Hydro Produksjon AS	Grane
Gullfaks	386.1	1978	Statoil ASA	050
Gullfaks Sør	100.2	1978	Statoil ASA	050
Gungne	20.0	1982	Statoil ASA	046
Gyda	48.5	1980	Talisman Energy Norge AS	019 B
Heidrun	226.1	1985	Statoil ASA	Heidrun
Heimdal	49.9	1972	Norsk Hydro Produksjon AS	036 BS
Hod	12.9	1974	BP Norge AS	033
Huldra	20.9	1982	Statoil ASA	Huldra
Jotun	25.5	1994	ExxonMobil Exploration and Production Norway AS	Jotun
Kristin	79.8	1997	Statoil ASA	Haltenbanken Vest
Kvitebjørn	74.1	1994	Statoil ASA	193
Mikkel	38.6	1987	Statoil ASA	Mikkel
Murchison	14.1	1975	CNR International (UK) Limited	Murchison
Njord	37.1	1986	Norsk Hydro Produksjon AS	Njord
Norne	103.0	1992	Statoil ASA	Norne
Ormen Lange[1)]	397.3	1997	Norsk Hydro Produksjon AS	Ormen Lange
Oseberg	476.4	1979	Norsk Hydro Produksjon AS	Oseberg
Oseberg Sør	60.2	1984	Norsk Hydro Produksjon AS	Oseberg Sør
Oseberg Øst	28.2	1981	Norsk Hydro Produksjon AS	053
Ringhorne Øst	6.0	2003	ExxonMobil Exploration and Production Norway AS	Ringhorne Øst

Field	Reserves mill. scm o.e.	Year of discovery[4]	Operator at 31.12.2006	Production licence/ unit area
Sigyn	17.8	1982	ExxonMobil Exploration and Production Norway AS	072
Skirne	10.9	1990	Total E&P Norge AS	102
Sleipner Vest	162.7	1974	Statoil ASA	Sleipner Vest
Sleipner Øst	120.9	1981	Statoil ASA	Sleipner Øst
Snorre	249.3	1979	Statoil ASA	Snorre
Snøhvit[1]	190.7	1984	Statoil ASA	Snøhvit
Statfjord	693.0	1974	Statoil ASA	Statfjord
Statfjord Nord	46.6	1977	Statoil ASA	037
Statfjord Øst	44.2	1976	Statoil ASA	Statfjord Øst
Sygna	12.7	1996	Statoil ASA	Sygna
Tambar	11.7	1983	BP Norge AS	065
Tor	37.2	1970	ConocoPhillips Skandinavia AS	Tor
Tordis	73.6	1987	Statoil ASA	089
Troll[2]	1614.3	1979	Norsk Hydro Produksjon AS	Troll
Troll[3]		1983	Statoil ASA	Troll
Tune	19.0	1996	Norsk Hydro Produksjon AS	190
Tyrihans [1]	67.8	1983	Statoil ASA	Tyrihans
Ula	89.8	1976	BP Norge AS	019
Urd	10.6	2000	Statoil ASA	128
Vale	3.8	1991	Norsk Hydro Produksjon AS	036
Valhall	178.6	1975	BP Norge AS	Valhall
Varg	15.1	1984	Talisman Energy Norge AS	038
Veslefrikk	61.1	1981	Statoil ASA	052
Vigdis	60.8	1986	Statoil ASA	089
Vilje[1]	8.7	2003	Norsk Hydro Produksjon AS	36
Visund	89.6	1986	Statoil ASA	Visund
Volve[1]	14.3	1993	Statoil ASA	046 BS
Åsgard	360.1	1981	Statoil ASA	Åsgard

1) Fields with approved development plans where production had not commenced at 31.12.2006

2) The resources include the total resources for Troll, including the part of the field operated by Statoil ASA

3) The resources are included in the row above

4) The year of the first discovery well 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. mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv. mill.scm o.e.
Alvheim[3]	25.5	5.6	0.0	0.0	31.1	25.5	5.6	0.0	0.0	31.1
Balder[a]	54.7	2.0	0.0	0.0	56.7	19.0	1.3	0.0	0.0	20.3
Blane[3]	0.8	0.0	0.0	0.0	0.9	0.8	0.0	0.0	0.0	0.9
Brage	50.8	2.6	0.8	0.0	55.0	3.5	0.2	0.0	0.0	3.7
Draugen	138.7	1.5	2.4	0.0	144.8	25.1	0.3	0.7	0.0	26.6
Ekofisk	540.3	154.2	14.6	0.0	722.2	162.8	22.9	2.8	0.0	191.0
Eldfisk	132.6	42.6	4.3	0.0	183.4	49.0	6.1	0.7	0.0	56.5
Embla	11.3	5.1	0.5	0.0	17.4	2.1	2.0	0.2	0.0	4.5
Enoch[3]	0.3	0.1	0.0	0.0	0.5	0.3	0.1	0.0	0.0	0.5
Fram	21.0	9.8	0.2	0.0	31.2	13.9	9.8	0.2	0.0	24.0
Gimle	4.0	0.8	0.1	0.0	5.0	3.5	0.7	0.1	0.0	4.4
Glitne	8.3	0.0	0.0	0.0	8.3	1.3	0.0	0.0	0.0	1.3
Grane	112.4	0.0	0.0	0.0	112.4	81.6	0.0	0.0	0.0	81.6
Gullfaks[b]	356.6	24.3	2.7	0.0	386.1	27.4	2.1	0.2	0.0	30.0
Gullfaks Sør[c]	47.9	42.6	5.1	0.0	100.2	20.7	26.4	3.2	0.0	53.2
Gungne	0.0	12.5	1.6	4.4	20.0	0.0	12.5	0.3	0.4	13.4
Gyda[d]	38.6	6.2	1.9	0.0	48.5	5.1	0.6	0.1	0.0	5.9
Heidrun	180.0	41.8	2.3	0.0	226.1	64.3	33.5	1.9	0.0	101.4
Heimdal	7.2	42.7	0.0	0.0	49.9	0.8	0.0	0.0	0.0	0.8
Hod	10.3	1.8	0.4	0.0	12.9	1.8	0.3	0.2	0.0	2.4
Huldra	4.9	15.7	0.1	0.0	20.9	0.7	3.7	0.0	0.0	4.5
Jotun	24.6	0.9	0.0	0.0	25.5	3.7	0.1	0.0	0.0	3.8
Kristin	33.7	31.1	6.8	2.1	79.8	32.6	28.3	6.2	0.0	72.7
Kvitebjørn	18.0	51.9	2.3	0.0	74.1	12.7	41.3	1.3	0.0	56.6
Mikkel	4.6	23.1	4.6	2.1	38.6	4.4	17.7	3.1	0.0	28.0
Murchison	13.7	0.4	0.0	0.0	14.1	0.3	0.1	0.0	0.0	0.3
Njord	24.0	10.5	1.4	0.0	37.1	3.0	10.5	1.4	0.0	16.1
Norne	90.0	10.7	1.2	0.0	103.0	17.3	5.7	0.7	0.0	24.3
Ormen Lange[3]	0.0	375.2	0.0	22.1	397.3	0.0	375.2	0.0	22.1	397.3
Oseberg[e]	353.7	108.6	7.4	0.0	476.4	19.0	92.6	3.2	0.0	117.5
Oseberg Sør	49.2	11.0	0.0	0.0	60.2	21.1	6.7	0.0	0.0	27.8
Oseberg Øst	27.8	0.4	0.0	0.0	28.2	11.7	0.2	0.0	0.0	11.9
Ringhorne Øst	5.8	0.2	0.0	0.0	6.0	4.8	0.2	0.0	0.0	5.0
Sigyn	0.0	6.6	3.0	5.6	17.8	0.0	3.3	1.7	1.8	8.3
Skirne	2.1	8.8	0.0	0.0	10.9	1.3	5.7	0.0	0.0	7.0
Sleipner Vest	0.0	117.8	8.1	29.6	162.7					

	Original reserves[1]					Remaining reserves[4]				
	Oil mill. scm	Gas bill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv. mill scm o.e.	Oil mill. scm	Gas bill.scm	NGL mill. tonnes	Condensate mill.scm	Oil equiv. mill.scm o.e.
Sleipner Øst[f]	0.0	68.1	13.1	27.9	120.9					
Sleipner Vest og Sleipner Øst[5]						0.0	50.1	3.9	3.5	60.9
Snorre	234.0	6.5	4.6	0.0	249.3	87.4	0.9	0.3	0.0	88.8
Snøhvit[3]	0.0	160.6	6.3	18.1	190.7	0.0	160.6	6.3	18.1	190.7
Statfjord	565.0	79.4	25.6	0.0	693.0	13.6	25.7	11.4	0.0	60.9
Statfjord Nord	42.1	2.7	0.9	0.0	46.6	8.6	0.6	0.2	0.0	9.6
Statfjord Øst	37.4	4.1	1.5	0.0	44.2	5.5	0.9	0.3	0.0	7.0
Sygna	12.7	0.0	0.0	0.0	12.7	3.8	0.0	0.0	0.0	3.8
Tambar	8.6	2.7	0.2	0.0	11.7	1.8	2.7	0.0	0.0	4.6
Tor	23.9	11.0	1.2	0.0	37.2	1.6	0.3	0.0	0.0	2.0
Tordis[g]	64.5	5.6	1.8	0.0	73.6	15.9	1.9	0.5	0.0	18.7
Troll[h]	231.7	1332.1	25.7	1.6	1614.3	50.7	1061.9	23.8	-2.7	1155.0
Tune[6]	3.2	15.6	0.1	0.0	19.0	0.2	3.2	0.0	0.0	3.5
Tyrihans[3]	29.0	29.3	5.0	0.0	67.8	29.0	29.3	5.0	0.0	67.8
Ula	80.0	3.8	3.1	0.0	89.8	12.3	0.0	0.6	0.0	13.4
Urd	10.5	0.1	0.0	0.0	10.6	8.3	0.0	0.0	0.0	8.3
Vale	1.7	2.2	0.0	0.0	3.8	1.1	1.7	0.0	0.0	2.8
Valhall	143.1	25.8	5.1	0.0	178.6	50.4	7.4	2.2	0.0	61.8
Varg	15.1	0.0	0.0	0.0	15.1	5.4	0.0	0.0	0.0	5.4
Veslefrikk	56.2	2.8	1.1	0.0	61.1	8.4	0.6	0.0	0.0	9.0
Vigdis	57.0	1.8	1.0	0.0	60.8	20.3	1.1	0.6	0.0	22.5
Vilje[3]	8.3	0.4	0.0	0.0	8.7	8.3	0.4	0.0	0.0	8.7
Visund	27.8	49.6	6.4	0.0	89.6	13.7	48.2	6.3	0.0	73.9
Volve[3]	12.4	1.3	0.2	0.1	14.3	12.4	1.3	0.2	0.1	14.3
Åsgard	99.8	178.3	34.7	16.0	360.1	49.5	126.0	25.7	-1.1	223.2
Sum	**4157.8**	**3152.8**	**209.7**	**129.7**	**7838.7**	**1049.3**	**2240.7**	**115.4**	**42.2**	**3551.4**

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 commenced at 31.12.2006

4) The reason for negative remaining reserve figures for NGL and condensate is that they have not been reported under original reserves

5) Measurements of gas production for Gungne, Sleipner Vest and Sleipner Øst are combined

a) Balder also includes Ringhorne

b) Gullfaks also includes Gullfaks Vest

c) Gullfaks Sør includes Gulltopp,Gullveig, Rimfaks og Skinfaks

d) Gyda also includes Gyda Sør

e) Oseberg also includes Oseberg Vest

f) Sleipner Øst also includes Loke

g) Tordis also includes Tordis Øst og Borg

h) Troll also includes TOGI

(Source: Norwegian Petroleum Directorate)

Table 2.4 Reserves in fields and discoveries that licensees have decided to develop

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
Yme [3]	7.8	0.0	0.0	0.0	7.8	1987
15/12-12 Rev		3.9		0.6	4.5	2001
24/9-5 Volund	7.2	0.8	0.0	0.0	8.0	1994
35/8-1 Vega		19.9	1.1	4.9	26.8	1981
35/9-1 Gjøa	11.1	32.6	5.6		54.5	1989
6507/3-1 Alve	0.0	5.8	0.9	1.4	8.9	1990
Total	**26.1**	**63.1**	**7.6**	**6.8**	**110.5**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year of the first discovery well drilled
3) The licensees have decided to develop the remaining resources in Yme

(Source: Norwegian Petroleum Directorate)

Table 2.5 Resources in discoveries in the planning phase

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
1/9-1 Tommeliten Alpha	6.7	13.9			20.6	1977
15/3-1S Gudrun	15.6	9.0	4.9		33.9	1975
15/5-1 Dagny		5.2	0.7	1.7	8.1	1978
2/12-1 Freja	2.9	0.6	0.0		3.5	1987
25/11-16	3.6	0.1	0.0		3.7	1992
25/5-5	3.5	0.1			3.6	1995
30/7-6 Hild [3]	5.0	15.6		1.9	22.5	1978
34/10-23 Valemon[4]		18.1	0.7	5.6	25.0	1985
35/11-13	6.4	2.8			9.2	2005
6406/3-2 Trestakk	11.3	2.0	0.6		14.3	1986
6506/11-7	8.3	3.1	0.8		12.9	2001
6507/11-6 Sigrid		1.9	0.3	0.36	2.9	2001
6507/3-3 Idun		11.9	1.2	0.3	14.4	1999
6507/5-1 Skarv [5]	16.4	34.4	4.5	4.0	63.4	1998
7122/7-1 Goliat [6]	28.0	10.6	0.0	0.0	38.6	2000
Sum	**107.9**	**129.2**	**13.6**	**13.8**	**276.8**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year of the first discovery well drilled
3) 30/7-6 Hild has resources in categories 4 og 5
4) 34/10-23 Valemon has resources in categories 4 and 7
5) 6507/5-1 Skarv has resources in categories 4 and 5
6) 7122/7-1 Goliat has resources in categories 4 and 5

(Source: Norwegian Petroleum Directorate)

Table 2.6 Resources in discoveries where development is likely but not clarified

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
1/3-6	3.2	2.8			6.0	1991
1/5-2 Flyndre	3.1	0.9			4.1	1974
15/3-4	3.3	1.6	0.8		6.4	1982
15/5-2		4.9	0.0	0.4	5.3	1978
15/8-1 Alpha		4.1	0.5	1.0	6.1	1982
16/7-2		1.6		0.7	2.3	1982
2/5-3 Sørøst Tor	3.1	0.9			3.9	1972
24/6-1 Peik		2.0		0.3	2.3	1985
25/8-4	1.0	0.0	0.0	0.0	1.0	1992
3/7-4 Trym		3.4		0.7	4.2	1990
33/9-6 Delta	0.1	0.0			0.2	1976
34/11-2 S Nøkken		2.7		1.2	3.9	1996
35/2-1		21.5			21.5	2005
35/8-1 Vega	0.9	0.4			1.3	1981
6406/1-1 Erlend N		1.1		0.3	1.4	2001
6406/1-2		2.3	0.4	0.9	3.8	2003
6406/2-1 Lavrans	5.1	12.6	3.2		23.7	1995
6406/2-6 Ragnfrid		2.5		1.7	4.2	1998
6406/2-7 Erlend		1.0		0.6	1.6	1999
6406/9-1		40.8		1.4	42.2	2005
6407/9-9	0.2	1.2		0.2	1.5	1999
6506/11-2 Lange	0.4	0.2			0.6	1991
6506/12-3 Lysing	1.5	0.3			1.8	1985
6506/6-1	0.0	89.3	2.8	5.0	99.6	2000
6605/8-1		26.0		2.6	28.6	2005
6507/2-2		6.0	1.0	0.4	8.3	1992
6507/7-13	0.9	0.0	0.0	0.0	1.0	2001
6608/11-2 Falk	13.5	0.3			13.8	2000
6706/6-1		25.0		2.5	27.5	2003
6707/10-1		38.3		1.4	39.7	1997
7/7-2	3.4	0.1			3.5	1992
7/8-3	2.4	0.1		0.2	2.7	1983
Total	**42.1**	**294.1**	**8.6**	**21.5**	**374.1**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year of the first discovery well drilled

(Source: Norwegian Petroleum Directorate)

Table 2.7 Resources in new discoveries that have not been evaluated

Discovery	Oil mill. scm	Gas mill. scm	NGL mill. tonnes	Condensate mill. scm	Oil equiv.[1] mill.scm o.e.	Year of discovery[2]
31/2-N-11 H	1.5				1.5	2005
6608/10-11 S	0.1	0.4			0.5	2006
7122/7-4 S Klappmys	0.7				0.7	2006
Total	**8,45**	**46,8**	**0,0**	**0,0**	**55,3**	

1) The conversion factor for NGL tonnes to scm is 1.9
2) The year of the first discovery well 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 337 active production licences and 339 operatorships. Both Statoil ASA and Norsk Hydro Produksjon AS are operators in production licences 085 and 085B. In addition, Gassco AS is the operator for large parts of the gas pipeline network. For more facts about the petroleum activities, please visit the Norwegian Petroleum Directorate's web site: www.npd.no. Various reports relating to production licences and licensees can be downloaded from www.npd.no/reports.

Tabell 3.1 Operatørar og rettshavarar

	Operatorship	Production licence	Field
A/S Norske Shell	10	23	7
BG Norge AS	14	23	
BP Norge AS	10	15	5
Centrica Resources Norge AS	3	4	
Chevron Norge AS	1	7	1
ConocoPhillips Scandinavia AS	10	12	9
DONG E & P Norge AS	5	32	7
Det Norske Oljeselskap AS	8	23	4
E.ON Ruhrgas Norge AS	1	10	1
Endeavour Energy Norge AS	3	17	2
Eni Norge AS	12	47	16
ExxonMobil Exploration and Production Norway A/S	9	24	16
Gaz de France Norge AS	1	28	3
Hess Norge AS	1	12	4
Idemitsu Petroleum Norge AS	1	13	6
Lundin Norway AS	14	24	2
Maersk Oil Exploration Norway AS	2	3	
Marathon Petroleum Norge AS	8	16	6
Nexen Exploration Norge AS	3	4	
Norsk Hydro Produksjon AS	68	135	49
Norske ConocoPhillips AS	2	26	14
Norwegian Energy Company AS	2	17	
OMV Norge AS	2	2	
Pertra ASA	7	13	3
Petro-Canada Norge AS	4	12	
Premier Oil Norge AS	1	10	1
RWE Dea Norge AS	5	28	7
Revus Energy ASA	4	48	4
Statoil ASA	100	173	50
Talisman Energy Norge AS	15	48	8
Total E&P Norge AS	13	72	40

Other licensees	Production licence	Field
Aker Exploration ASA	1	
Altinex Oil AS	9	1
Brigde Energy AS	1	
Discover Petroleum AS	1	
Edison International Spa	5	
Ener Petroleum ASA	1	
Enterprise Oil Norge AS	10	7
Faroe Petroleum Norge AS	6	
Mobil Development Norway AS	26	9
Noble Energy Limited	3	
Norske AEDC A/S	1	1
PA Resources Norway AS	12	1
Petoro AS	112	41
Rocksource ASA	1	
Serica Energy Ltd	2	
Svenska Petroleum Exploration AS	4	3
Wintershall Norge AS	4	

(Source: Norwegian Petroleum Directorate)

Appendix 4 List of addresses

GOVERNMENT BODIES

The Ministry of Petroleum and Energy
P.O. Box 8148 Dep, 0033 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 65
www. regjeringen.no/oed

The Norwegian Petroleum Directorate
P.O. Box 600, 4003 Stavanger
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 and Social Inclusion
P.O. Box 8019 Dep, 0030 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 76
www. regjeringen.no/aid

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, Fax +47 22 24 95 10
www. regjeringen.no/finans

The Ministry of the Environment
P.O. Box 8013 Dep, 0030 Oslo
Tel. +47 22 24 90 90, Fax +47 22 24 95 60
www. regjeringen.no/md

OPERATORS

A/S Norske Shell
P.O. Box 40, 4098 Tananger
Tel. +47 51 69 30 00, Fax +47 51 69 30 30
www.shell.com

BG Norge AS
P.O. Box 780 Sentrum, 4004 Stavanger
Tel. +47 51 20 59 00, Fax +47 51 20 59 90
www.bg-group.com

BP Norge AS
P.O. Box 197 Forus, 4065 Stavanger
Tel. +47 52 01 30 00, Fax +47 52 01 30 01
www.bp.no

Centrica Resources Norge AS
P.O. Box 520
4003 Stavanger
www.centrica.com

Chevron Norge AS
P.O. Box 97 Skøyen, 0212 Oslo
Tel. +47 22 13 56 60, Fax +47 22 13 56 96
www.chevron.com

ConocoPhillips Skandinavia AS
P.O. Box 220, 4098 Tananger
Tel. +47 52 02 00 00, Fax +47 52 02 66 00
www.conocophillips.com

Det Norske Oljeselskap AS
P.O. Box 1345 Vika, 0113 Oslo
Tel. +47 23 23 84 80, Fax +47 23 23 84 81
www.dno.no

DONG E & P Norge AS
P.O. Box 450 Sentrum, 4002 Stavanger
Tel. +47 51 50 62 50, Fax +47 51 50 62 51
www.dong.no

Endeavour Energy Norge AS
P.O. Box 1989 Vika, 0125 Oslo
Tel. +47 22 01 04 70, Fax +47 22 01 04 71
www.endeavourcorp.com

Eni Norge AS
P.O. Box 101 Forus, 4064 Stavanger
Tel. +47 51 57 48 00, Fax +47 51 57 49 30
www.eninorge.no

E.ON Ruhrgas Norge AS
P.O. Box 640 Sentrum, 4003 Stavanger
Tel. +47 51 51 74 00, Fax +47 51 51 74 10
www.ruhrgas.no

ExxonMobil Exploration and Production Norway AS
P.O. Box 60 Forus, 4064 Stavanger
Tel. +47 51 60 60 60, Fax +47 51 60 66 60
www.exxonmobil.no

Gassco AS
P.O. Box 93, 5501 Haugesund
Tel. +47 52 81 25 00, Fax +47 52 81 29 46
www.gassco.no

Gaz de France Norge AS
P.O. Box 242 Forus, 4066 Stavanger
Tel. +47 52 04 46 00, Fax +47 52 04 46 01
www.gazdefrance.com

Hess Norge AS
P.O. Box 130, 4065 Stavanger
Tel. +47 22 94 00 00, Fax +47 22 42 63 27
www.hess.com

Idemitsu Petroleum Norge AS
P.O. Box 1844 Vika, 0123 Oslo
Tel. +47 23 23 85 00, Fax +47 23 23 85 01
www.idemitsu.no

Lundin Norway AS
Strandveien 50 D, 1366 Lysaker
Tel. +47 67 10 72 50, Fax +47 67 10 72 51
www.lundin-petroleum.com

Marathon Petroleum Norge AS
P.O. Box 480 Sentrum, 4002 Stavanger
Tel. +47 51 50 63 00, Fax +47 51 50 63 01
www.marathon.com

Mærsk Oil Exploration Norway AS
P.O. Box 244, 1326 Lysaker
Tel. +47 67 10 76 00, Fax +47 67 10 76 01
www.maerskoil.com

Nexen Exploration Norge AS
P.O. Box 6641 St Olavs Plass
c/o Simonsen Føyen Advokatfirma DA
0129 OSLO
Tel. +47 21 95 55 00, Fax +47 21 95 55 01

Norsk Hydro Produksjon AS
0240 Oslo
Tel. +47 22 53 81 00, Fax +47 22 53 27 25
www.hydro.com

Norske ConocoPhillips AS
P.O. Box 220, 4098 Tananger
Tel. +47 52 02 00 00, Fax +47 52 02 66 00
www.conocophillips.no

Norwegian Energy Company AS
P.O. Box 550 Sentrum, 4003 Stavanger
Tel. +47 99 28 39 00, Fax +47 51 53 33 33
www.noreco.no

OMV Norge AS
c/o OMV Exploration & Production GmbH
Gerasdorfer Strasse 151
1210 Vienna
Austria
www.omv.com

Pertra ASA
Nedre Bakklandet 58 C, 7014 Trondheim
Tel. +47 90 70 60 00, Fax +47 73 53 05 00
www.pertra.no

Petro-Canada Norge AS
P.O. Box 269 Sentrum
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Tel. +47 51 21 50 00, Fax +47 51 21 50 99
www.petro-canada.com

Premier Oil Norge AS
P.O. Box 800 Sentrum
4004 Stavanger
Tlf: 51 21 31 00,
www.premieroil.co.uk

Revus Energy ASA
P.O. Box 230 Sentrum, 4001 Stavanger
Tel. +47 51 50 63 50, Fax +47 51 50 63 51
www.revus-energy.no

RWE Dea Norge AS
P.O. Box 243 Skøyen, 0213 Oslo
Tel. +47 21 30 30 00, Fax +47 21 30 30 99
www.rwe-dea.no

Statoil ASA
4035 Stavanger
Tel. +47 51 99 00 00, Fax +47 51 99 00 50
www.statoil.com

Talisman Energy Norge AS
P.O. Box 649 Sentrum, 4003 Stavanger
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www.talisman-energy.com

Total E&P Norge AS
P.O. Box 168 Sentrum, 4001 Stavanger
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www.total.no

OTHER LICENCEES

Aker Exploration ASA
Fjordalleen 16
0115 Oslo
Tel. +47 24 13 00 00, Fax +47 24 13 01 06
www.akerasa.com

Altinex Oil AS
P.O. Box 3162, 9498 Harstad
Tel. +47 77 05 93 00
www.altinex.no

Bridge Energy AS
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Discover Petroleum AS
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Ener Petroleum ASA
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www.1petro.com

Enterprise Oil Norge AS
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P.O. Box 40, 4098 Tananger
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www.shell.com

Faroe Petroleum Norge AS
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www.faroe-petroleum.com

Mobil Development Norway AS
c/o ExxonMobil Exploration
and Production Norway AS
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Noble Energy (Europe) Limited
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Kent, TN13 1XE
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Fax +47 +44 1732 464 140
www.nobleenergyinc.com

Norske AEDC A/S
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www.aoc.co.jp

PA Resources Norway AS
Munkedamsveien 45 E, 0250 Oslo
Tel. +47 21 56 76 00, Fax +47 21 56 76 01
www.paresources.se

Petoro AS
P.O. Box 300 Sentrum, 4002 Stavanger
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www.petoro.no

Rocksource ASA
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Serica Energy (UK) Ltd
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Svenska Petroleum Exploration AS
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Wintershall Norge AS
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www.wintershall.biz

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	litre
	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

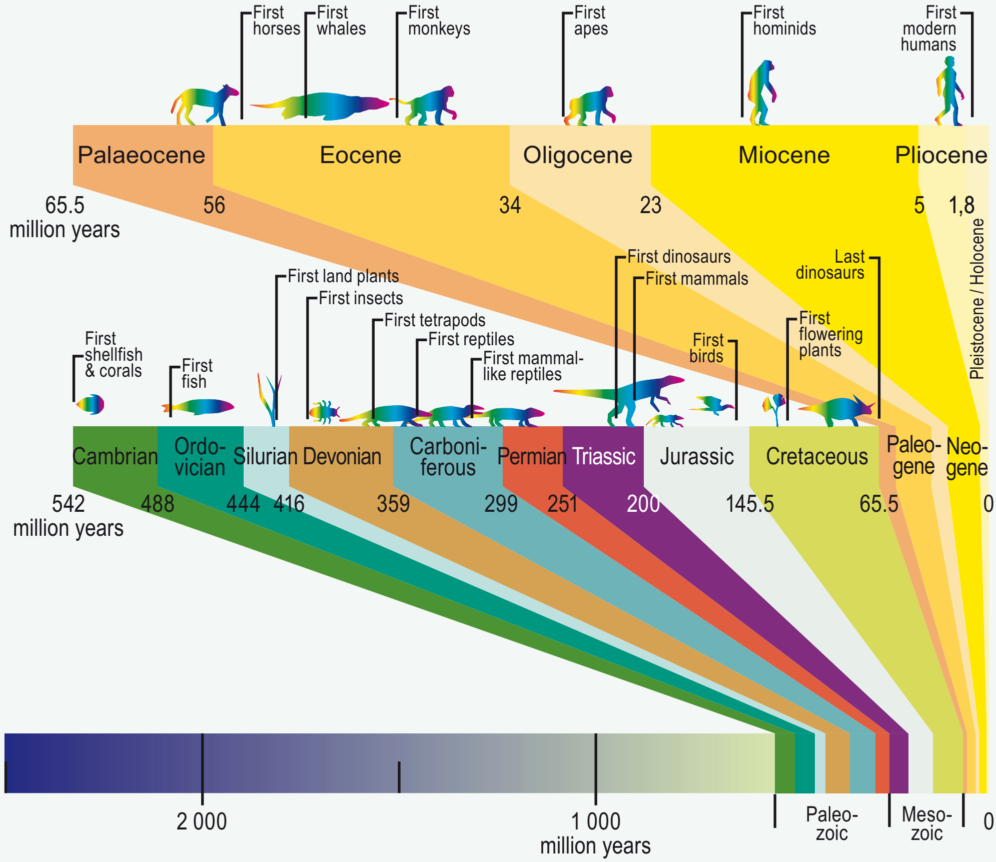
Conversion factors for volume

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



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